MODELLING EXPLORATION SUCCESS IN ALBERTA OIL PLAYS

Kenneth D. Foat
Alan F. MacFadyen

CANADIAN ENERGY RESEARCH INSTITUTE

Study No. 19, September, 1983
ISBN 0-920522-29-7
THE UNIVERSITY OF CALGARY PRESS

MODELLING EXPLORATION SUCCESS IN ALBERTA OIL PLAYS

Kenneth D. Foat
and
Alan J. MacFadyen

ISBN-0-920522-29-7

CANADIAN ENERGY RESEARCH INSTITUTE
3512 - 33 STREET N.W.
CALGARY, ALBERTA
T2L 2A6
PRICE $15.00

September 1983

The Canadian Energy Research Institute is a co-operative research organization sponsored by five parties: Energy, Mines and Resources Canada, the Alberta Department of Energy and Natural Resources, the Private Energy Research Association (composed of corporate and individual members from oil, gas, coal, electrical, nuclear energy and pipeline companies), The University of Calgary and the Ontario Ministry of Energy. The objectives of the Institute are to develop an economic research capability and to conduct studies that will assist industry and government in dealing with energy problems. The research program of the Institute is developed by a Board of Directors named by the sponsoring organizations. The content of the individual studies is, however, the responsibility of the authors.

In addition to undertaking studies in energy economics funded collectively by the five Institute sponsors, CERI carries out research for clients on a contractual basis.

TABLE OF CONTENTS

LIST OF FIGURES ix

LIST OF TABLES xi

PREFACE xiv

EXECUTIVE SUMMARY xv

INTRODUCTION 1

CHAPTER 1 TOWARDS A CONCEPTUAL FRAMEWORK FOR OIL SUPPLY 3

1.1 A Simple View of Supply 3
1.2 Assumptions 3
1.3 A More Inclusive Perspective: The Physical Model 4
1.4 A More Inclusive Perspective: The Economic Model 6

CHAPTER 2 A CONCEPTUAL MODEL OF OIL SUPPLY 13

2.1 Operation 13

2.1.1 Technical Considerations 13
2.1.2 Political Considerations 15

2.2 Development 17
2.3 Exploration 18

CHAPTER 3 THE EXPLORATORY PHASE OF CRUDE OIL PRODUCTION: AN EMPIRICAL ANALYSIS 23

3.1 Introduction 23
3.2 The Investigative Unit 24
3.3 General Methodology 27
3.4 Model Specification and Results 29

3.4.1 The Reserves Discovery Equations 29
3.4.2 Conclusion and Implications 43

CHAPTER 4 EXTENSIONS TO THE ANALYSIS 55

4.1 Introduction 55
4.2 Sequence of Oil Plays 55
4.3 Exploratory Drilling Equations 59

4.3.1 Introduction 59
4.3.2 Aggregate Exploratory Drilling in Alberta 61
4.3.3 Exploration Equations for Different Oil Plays 66

4.4 Oil Discovery and Enhanced Recovery in Alberta 69

CHAPTER 5 SUMMARY 73

APPENDIX A REVIEW OF TAX TREATMENT ON ALBERTA PETROLEUM 77

A.1 Royalties 79
A.2 Corporate Income Tax Provisions 81
A.3 Land Provisions 84
A.4 Exploratory Incentives Schemes 85
A.5 Effect of Tax Regulations on Oil Profits 86

A.5.1 Introduction 86
A.5.2 Effect of Taxes on a Project 86

APPENDIX B CHARACTERISTICS OF ALBERTA OIL PLAYS 103

B.1 Introduction 105
B.2 Comparative Characteristics of Different Plays 106
B.3 Discovered Pools as a Statistical Sample 106

B.3.1 Data Base 110
B.3.2 Random Sampling 111
B.3.3 Distribution of Population Parameters 113
B.3.4 Conclusion 115

B.4 Simple Correlations Among Variables in Oil Plays 116
B.5 Conclusion 117

APPENDIX C CRUDE OIL RESERVES BY GEOLOGICAL HORIZON: HISTORY AND APPRECIATION 119

C.1 History of Discovery 121
C.2 The 'Reserve' Data Base 131
C.3 Reserve Appreciation 133

APPENDIX D MEASURES OF EXPLORATORY ACTIVITY IN ALBERTA 161

D.1 Nature of the Data Base 163
D.2 A Tabular Summary of Exploratory Effort 165

LIST OF FIGURES

1.1	Conceptual Chart of Crude Petroleum Activities and Products	5
1.2	The Economic Process of Crude Petroleum Production	8
3.1	Simplified Geological Cross Section of Alberta Showing the Seven Plays	25
3.2	Geological Distribution of Proved Reserves of Crude Oil, Alberta, 1976	26
3.3	Oil Discovery Curves	37
C.1	Simplified Geological Cross Section Showing the Seven Plays	122
C.2	Geological Distribution of Proved Reserves of Crude Oil	123
C.3	Overview of Play Discoveries: Leduc (D-3), Woodbend Group, Lower Upper Devonian	124
C.4	Overview of Play Discoveries: Nisku (D-2), Winterburn Group, Upper Devonian	125
C.5	Overview of Play Discoveries: Viking, Colorado Group, Lower Cretaceous	126
C.6	Overview of Play Discoveries: Cardium, Colorado Group, Lower Cretaceous	127
C.7	Overview of Play Discoveries: Granite Wash, Middle to Upper Devonian	128
C.8	Overview of Play Discoveries: Beaverhill Lake, Middle and/or Upper Devonian	129
C.9	Overview of Play Discoveries: Keg River, Elk Point Group, Middle Devonian	130
D.1	Map of Alberta Showing ERCB Area Codes	164

LIST OF TABLES

3.1	Reserves Discovery Equation: Regression Results	39
3.2	Average Discovery Size Regression Results	44
3.3	Alberta Oil Discoveries, 1977-1980, 8 Plays	47
4.1	Comparative Data on Alberta Oil Plays Listed by Discovery Date	57
4.2	Play Exploration Share Equations: Regression Results	67
A.1	Corporate Income Tax Rates	82
A.2	Unit Values of Alberta Crude Oil and Natural Gas	95
A.3	Comparison of Various Measures of Real Per Unit Oil and Gas Values	98
B.1	Comparative Play Characteristics: Aggregate Levels	107
B.2	Comparative Play Characteristics: Averages	108
B.3	Comparative Play Characteristics	109
B.4	Values of Z for Test of Runs Above and Below the Median ..	112
B.5	Tests for Normality and Log Normality	114
C.1	Annual Reserve Estimates: The Seven Major Plays	132
C.2a	Annual Reserve Estimates and Member Reservoirs Leduc (D-3)	134
C.3b	Historical Appreciation of Initial Oil in Place - Leduc (D-3)	135
C.4b	Historical Appreciation of Total Recoverable Oil - Leduc (D-3)	136
C.5a	Annual Reserve Estimates and Member Reservoirs Nisku (D-2)	137
C.6b	Historical Appreciation of Initial Oil in Place - Nisku (D-2)	138

C.7b Historical Appreciation of Total Recoverable Oil - Nisku (D-2) 139

C.8a Annual Reserve Estimates and Member Reservoirs Viking 140

C.9b Historical Appreciation of Initial Oil in Place - Viking 141

C.10b Historical Appreciation of Total Recoverable Oil - Viking 142

C.11a Annual Reserve Estimates and Member Reservoirs Cardium 143

C.12b Historical Appreciation of Initial Oil in Place - Cardium 144

C.13b Historical Appreciation of Total Recoverable Oil - Cardium 145

C.14a Annual Reserve Estimates and Member Reservoirs Granite Wash 146

C.15b Historical Appreciation of Initial Oil in Place - Granite Wash 147

C.16b Historical Appreciation of Total Recoverable Oil - Granite Wash 148

C.17a Annual Reserve Estimates and Member Reservoirs Beaverhill Lake 149

C.18b Historical Appreciation of Initial Oil in Place - Beaverhill Lake 150

C.19b Historical Appreciation of Total Recoverable Oil - Beaverhill Lake 151

C.20a Annual Reserve Estimates and Member Reservoirs Keg River 152

C.21b Historical Appreciation of Initial Oil in Place - Keg River 153

C.22b Historical Appreciation of Total Recoverable Oil - Keg River 154

C.23 Appreciation in Recent Discoveries by Play 156

D.1	New Field Wildcats - Number	166
D.2	All Exploratory Wells - Number	167
D.3	All Exploratory Wells - Average Depth	168
D.4	All Exploratory Wells - Oil Successes	169
D.5	All Exploratory Wells - Gas Successes	171
D.6	Penetrations to the Leduc (D-3) Formation	172
D.7	Penetrations to the Nisku (D-2) Formation	173
D.8	Penetrations to the Viking Formation	174
D.9	Penetrations to the Cardium Formation	175
D.10	Penetrations to the Granite Wash Formation	176
D.11	Penetrations to the Beaverhill Lake Formation	177
D.12	Penetrations to the Slave Point Formation	178
D.13	Penetrations to the Keg River Formation	179
D.14	Penetrations to the Sulphur Point Formation	180

PREFACE

Financial support from Energy, Mines and Resources Canada and Imperial Oil Limited (for gathering, assembling and processing the data base) is gratefully acknowledged. The Alberta Energy Resources Conservation Board kindly allowed access to their records to build up this data base. The study could not have been completed without the help of a number of individuals, to whom we express our thanks: George Isherwood (for gathering the basic historical data on various oil plays), Shane Streifel, Russel MacNabb, Gordon Douglas, Mark Brown and Dr. W. Haessel (for their aid and advice in processing the data), Shirley Ingstrup and Janice Tener (for their continued good humor in making the manuscript readable) and Dr. J. Dawson and Dr. G. E. Angevine (for their continued encouragement). We would also like to thank the four reviewers of the manuscript for their helpful comments.

EXECUTIVE SUMMARY

This study deals with the aggregate supply of crude oil reserves in Alberta. In actuality, reserve additions result from the myriad of decisions undertaken by individual companies in light of their various objectives, circumstances and expectations. But, from a public policy point of view, interest focuses not so much on the specific decision of a particular producer, but on the sum of such actions. The search for models which capture the essence of this aggregate activity is an ongoing challenge for economic research. This study follows the lead of such analysts as Ryan and Uhler in arguing that a better understanding of the historical development of the Alberta petroleum industry is attainable if the analysis allows for some geological disaggregation by examining the major crude oil plays separately.

Chapters 1 and 2 are introductory and have been written for those who view the crude oil supply problem primarily in physical-technical terms; they set out the major economic dimensions of the crude petroleum exploration, development and operation phases.

Chapter 3 is the major empirical chapter dealing with the historical discovery process for crude oil-in-place and primary recoverable reserves in nine Alberta oil plays--five major [Leduc (D-3), Nisku (D-2), Cardium Sandstone, Beaverhill Lake and Keg River] and four minor (Viking, Granite Wash, Slave Point and Sulphur Point). The hypothesis tested is that the discovery process in each play tends to follow a pronounced negative exponential trend. Clearly, this is a stylized view of a discovery process which involves such great uncertainty, but it is found that the hypothesis is statistically significant in four of the major plays (Leduc, Nisku, Beaverhill Lake and Keg River). The results suggest that only in the Keg River play could significant reserve additions be expected after 1976. It is also shown that the negative exponential relationship applies to average discovery size in these four plays, as well as to total volumes of oil.

Chapter 4 reports several less significant extensions to the analysis. It is noted that the model as tested in Chapter 3 is not applicable to enhanced recovery (secondary and tertiary) reserves, nor

to oil in plays not yet discovered, nor to the oil volumes outside the nine plays considered. It is also noted that the model does not completely describe the discovery process, since it argues that discoveries may exhibit a negative exponential response to increased penetrations of a geological formation, but it does not explain how many penetrations to a formation will occur in any year. Preliminary analysis suggests that the number of penetrations to a specific formation is positively related to the ratio of the average discovery size in that formation to the average discovery size in the province as a whole in the previous year; in other words, there is some evidence of geological directionality in oil exploration.

Four appendices to the study present the main underlying data. Appendix A reviews the major government regulations affecting crude petroleum operations in Alberta from 1947 through 1976, and presents some price and netback (after-tax) values for crude oil and natural gas. Appendix B presents statistical information on the main oil plays considered, including means and standard deviations for a variety of physical characteristics of the oil pools in each play. It also includes several statistical tests of the normality or log-normality of those pool characteristics. Appendix C includes brief descriptions of the major oil plays considered, and the basic oil reserve information for each play, including discovery data for years from 1947 through 1976 and a discussion of average pool appreciation factors. Appendix D includes the basic data on exploratory well penetrations to various geological plays, for 28 regions making up the total province, for years from 1947 through 1976.

INTRODUCTION

General Remarks

Economics is related to the physical production of conventional oil in two major ways.

- The utilization of society's scarce resources (labour, capital, land, energy, and other materials) in any particular productive endeavour precludes the use of those same inputs elsewhere in the economy, and therefore involves an opportunity cost equal to the social value of other goods or services which might have been produced: in oil production, as elsewhere, 'there is no such thing as a free lunch'.

- Oil production is a voluntary act--it is 'motivated'--and foremost amongst stimuli are economic incentives (profits).

One could draw a picture of the oil industry in purely physical terms, using principles of reservoir engineering and detailed descriptions of various drilling, lifting and processing techniques but such a picture would be incomplete. The technological ability to perform a physical activity is no guarantee that anyone will be willing to do it, nor that society will find it advantageous if someone does do so. At the same time, a description of oil production in terms of economic variables must be compatible with the underlying physical realities--the known techniques of production, and nature's laws.

Objectives and Format

This study considers the economics of conventional crude oil production in Alberta, in light of some of the physical constraints that exist. The constraint of prime concern in the analysis which follows is the limited nature of the natural resource base. Conventional oil is a depletable natural resource, available in the ground in finite volume; if the industry is to continue in a particular region new discoveries must proceed along with production, but each new find leaves a diminished total of still undiscovered resources. The study has been motivated by the hypothesis that a clearer understanding of the effect of this physical limitation on the economical recovery of

oil can be obtained if the oil discovery process is considered separately for major geologically defined oil plays.

The study is divided into four chapters, a summary (Chapter 5) and four appendices. The first two chapters are a basic review of petroleum industry activities, written largely for those unfamiliar with the physical tasks involved or those with little background in economic evaluation. Chapters 3 and 4 include the empirical analysis. Of these, Chapter 3 is the most important; it provides statistical support for the argument that discoveries of oil-in-place and primary recoverable reserves in most major Alberta oil plays follow a similar pattern with strongly diminishing returns. This appears to be true both for volumes of oil and for average discovery size. Chapter 4 provides preliminary evidence on attempts to extend the analysis. It notes that the basic model applied to single oil plays is not suitable for analyzing the sequence of oil plays, or to oil recoverable by secondary or tertiary recovery processes. It also considers the relationship between the share of drilling activity in a play and the physical returns to drilling in that play, relative to the province as a whole. The appendices examine: the history of royalty and tax treatment of Alberta oil from 1947-1976, and the effects on netback values (Appendix A); the characteristics of seven main Alberta oil plays (Appendix B); the volumes of oil in the major plays, by year of discovery (Appendix C); and the amount of exploratory drilling in Alberta since 1947 by geographic region and oil play (Appendix D).

Chapter 1

TOWARDS A CONCEPTUAL FRAMEWORK FOR OIL SUPPLY

This chapter begins with discussion of a very simplistic economic supply model and then proceeds to a more realistic representation of the conventional crude oil industry in both physical and economic terms. The material is not original, but has been organized to point out the complementarities between two different perspectives of the petroleum industry--one focussing on the technical tasks involved, the second on the economic cost of oil.

1.1 A Simple View of Supply

In rudimentary economic theory, competitive equilibrium prices are determined by the equality of 'demand' and 'supply'. Supply is characterized as the relationship between product price and the quantity of the product suppliers are willing and able to bring to the market. Since price and sales volume data for Alberta crude oil are readily available, one could, seemingly, estimate the historical correlation between the quantity of oil supplied and its price in order to quantify an economic supply function.[1]

Such a straightforward correlation is complicated by a variety of factors, including:

- the problem of separating demand and supply factors;[2]
- assumptions pertaining to the competitive nature of the industry; and
- variables, other than price, which influence the supply curve.[3]

As a result, a static relationship between only price and quantity supplied, which is readily amenable to empirical analysis, does not exist. However, this simple view of supply does provide a foundation upon which a more realistic framework can be developed.

1.2 Assumptions

Analysis of a complex issue necessitates simplifying assumptions. The following general assumptions will be considered valid for

the purposes of this study.

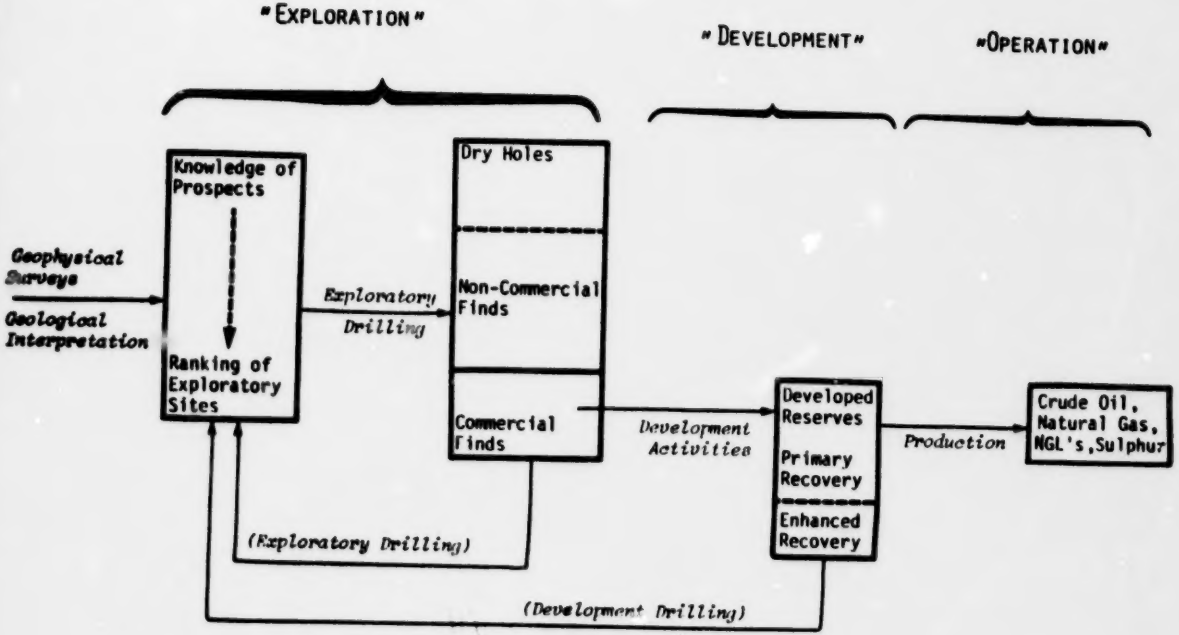
- Individual firms are profit maximizers.
- The firms in the industry are 'price-takers' in both the input and output markets.
- Firms react to the expected (mean) value of those variables which influence their production, independent of the range of possible outcomes (this allows one to abstract from the many stochastic elements in the petroleum industry). In practice companies may consider the whole range of possible outcomes in calculating the mean values, as with Monte Carlo methods.
- Lags in response, other than those associated with the fixed nature of capital, are generally assumed to be very short, usually less than a year.
- We can deal with the industry in the aggregate, rather than individual firms.

More specifically, the basic behavioural assumption is that firms act to maximize their profits, subject to the following conditions:

- Prices, taxes and input costs are taken as given to the individual firm, but are subject to change over time.
- Allowable production has been affected by market demand prorationing regulations.
- The activities of the firm may be affected by short-term constraints on capital equipment or available reserves, and are subject to a more binding constraint--the overall physical availability and producibility of conventional oil, as bequeathed by nature.
- Technology and knowledge are subject to change, with geological information particularly prone to abrupt shifts.
- The industry in Alberta produces joint products.

1.3 A More Inclusive Perspective: The Physical Model

A schematic diagram (Figure 1.1) is utilized to illustrate the physical activities involved in the various phases of petroleum production.



NOTE: The boxes represent the 'output' of various industry activities; the lines indicate the activity which generates that output.

Figure 1.1: Conceptual Chart of Crude Petroleum Activities and Products

The ultimate physical objective of companies, as depicted, is the production of crude petroleum, although a number of other physical tasks are antecedent to this end.[4] The 'products' of these intermediate tasks are summarized below.

Activity	Product
geological/geophysical surveys	knowledge of drilling prospects, thereby allowing them to be ranked
exploratory drilling	discovered accumulations of petroleum in the ground, which may be either commercial or non-commercial to produce (at current prices)
development drilling	the delineation of proved established reserves, capable of sustaining production
operation	crude petroleum[5]

There are three further comments about Figure 1.1.

- The physical tasks denoted are greatly oversimplified. Development, for instance, involves activities as diverse as drilling water disposal wells, and installing storage equipment and gathering lines. Likewise, at the exploratory level, the diagram abstracts entirely from the activity of land acquisition, even though mineral rights are often resold, in whole or in part, before or after procuring information.

- The relevance of such an anatomization of the production process depends upon the subsequent availability of data for empirical analysis. Certain variables, 'knowledge' in particular, are not directly measurable.

- The physical processes, as represented therein, are not directly amenable to economic analysis. The reason is that the description of physical activities does not make explicit the behavioural underpinnings of the industry. The objective of companies is not produced oil but an excess of revenues over costs.

1.4 A More Inclusive Perspective: The Economic Model

Revenues (gross) may be defined as the sales value of each individual unit of output summed over all such units. Similarly, costs can be calculated as the cost of individual inputs, added up for all

inputs. The intermediate outputs (knowledge, discovered or developed reserves) also have distinct values and costs; but, since these goods are not frequently sold in the market place, their values might be called 'imputed' or 'shadow' values.

The traditional assumption is that individual firms take the input and output prices as given by the marketplace; however, they have the ability to select among a number of different possible input combinations in the production of any given amount of output. Conventional (neo-classical) economic theory summarizes this production decision in the concept of a 'production function', which shows the technologically most efficient ways to combine inputs so as to yield various amounts of output. The physical input combination selected will be chosen on economic (i.e., least-cost) criteria from such an array of alternatives.

The same crude oil production process as illustrated in Figure 1.1 is modified to incorporate the essential 'economic' dimension in Figure 1.2.

Again, there are four main 'outputs' specified from the phases of crude oil production: knowledge of prospects (K), presence or absence of oil at a location (P), developed reserves (R), and produced petroleum (O). The subscripts (or sub-subscripts as the case may be) i, j, k, and m associated with these quantities indicate that a number of qualitatively different products result. Also, four main intermediate inputs exist: labour services (L), capital equipment (C), materials and energy flows (M), and land (D). Per unit values are represented by the symbol p for final output, c for purchased inputs, and by c* for imputed values of inputs. Finally, a production function relationship is presented by $f(\ ) = g(\ )$, where the f and g denote some functional relationship between input and output quantities, respectively.

In summary, Figure 1.2 conveys, first, that economic analysis of the industry requires a consideration of output values, input costs and production technology, and second, that such a procedure, even at this basic conceptual level, is complex.[6]

The notion of profit maximization is best interpreted as the maximization of the present value of net revenues.[7] The discounting present value provision serves to point out a characteristic of the economics of crude oil production which neither Figure 1.1 or Figure 1.2 addresses directly. Oil production, from exploration through to abandonment of a reservoir, takes place over time, so that the method

Economic Correlates	Activity			
	"Exploration"		"Development"	"Operation"
	Knowledge of Prospects	Occurrence of Oil		
Quantities:	$f^K[L^K, C^K, M^K, D^K, (g^P)] = g^K(K_1, \ldots, K_i)$	$f^P[L^P, C^P, M^P, D^P, (g^K)] = g^P(P_1, \ldots, P_j)$	$f^R[L^R, C^R, M^R, D^R, (g^P)] = g^R(R_1, \ldots, R_k)$	$f^O[L^O, C^O, M^O, D^O, (g^R)] = g^O(O_1, \ldots, O_m)$
Values:				
Inputs:	$(c_L, c_C, c_M, c_D, c_P^*)$	$(c_L, c_C, c_M, c_D, c_K^*)$	$(c_L, c_C, c_M, c_O, c_P^*)$	$(c_L, c_C, c_M, c_O, c_R^*)$
Outputs:	$(c_{K_1}^*, \ldots, c_{K_i}^*)$	$(c_{P_1}^*, \ldots, c_{P_j}^*)$	$(c_{R_1}^*, \ldots, c_{R_k}^*)$	$(p_{O_1}, \ldots, p_{O_m})$

Legend:

Outputs:
- K, knowledge of prospects, from 1 to i.
- P, presence or absence of oil, at locations from 1 to j.
- R, developed reserves, in deposits from 1 to k.
- O, produced petroleum and byproducts, from various deposits.

Inputs:
- L, labor services
- C, capital equipment
- M, materials and energy
- D, land

Figure 1.2: The Economic Process of Crude Petroleum Production

of analysis should be dynamic. The implications of a dynamic frame of reference are many.

In simple conceptual terms one might imagine a company facing a future extending indefinitely, in each year of which it is presented with a set of alternatives such as those shown in Figure 1.2. The objective, though, is not to maximize the profits in any single year but to maximize the present value of total profits over all years. Complications abound at this juncture, some of which have been previously alluded to, while others warrant further discussion.

- One might simplify changes in prices, costs and the technology of production by assuming constant values within a year, but over a longer horizon such changes must be incorporated.

- In a dynamic system the temporal rigidities of various inputs must be recognized. For instance, the operator is interested in all variable costs and revenues, but it takes time to install new capital equipment, and, once installed, such equipment survives whether or not it is required. Likewise, information and expectations about various drilling prospects are not only a function of current inputs but also the accumulated fund of knowledge generated from the previous applications of such inputs. Indeed, the knowledge gained earlier might be considered a fixed-input to which other inputs are added to generate the current period's incremental contribution. Similarly, the amount of reserves developed is not simply a function of variable inputs leading to this year's exploratory successes, but all past exploratory results. The current production of crude oil depends only to a minor extent on reserves developed in the current year, and mainly on those developed in the past.

- An 'ideal' production function, then, should convey not only the feasible combinations of inputs when all technical combinations are open, but also the courses of action available when some inputs are fixed. Expressed in other words, a complete model would be dynamic not only in terms of the changes in the parameters of the production function over time, but also in terms of the optimal time-path of inputs for a given production function, in light of the 'quasi-fixed' nature of some inputs.

- A final dynamic consideration relates to the role in the analysis of the imputed (shadow) costs for intermediate output. If analysis is explicitly undertaken using a net present value formulation over the future, then these imputed costs can be assigned a zero value: the company is concerned with the present value of actual expenditures and receipts as reflected in the market prices. An

alternative, and equivalent, approach is available which focuses on the costs and revenues in the present year, shifting the consideration of the future onto the imputed prices of the intermediate inputs (i.e., c^*_K, c^*_P and c^*_R in Figure 1.2). This method has been most fully analysed for the imputed value of a unit of developed reserves removed from the reservoir as production (i.e., c^*_R). This is referred to as the 'marginal user cost' of the oil and has a value equal to the present value of the future profit foregone by not waiting until the future to produce.[8] Obviously the magnitude of this opportunity cost depends upon future cost and revenue conditions. The imputed values of the other intermediate products represent similar costs. Referring to Figure 1.2, c^*_P is the maximum profit that would be expected if a prospect were left to a future date to be drilled, instead of drilling today; similarly, c^*_K is the maximum profit that can be earned by delaying the gathering of a new piece of information about drilling prospects.

In summary, regardless of the approach taken, the profit maximizing course of action depends upon the operators' conceptions of revenues and costs throughout time, which in turn depend in part upon the nature of the dynamic production function describing the available techniques of production.

Footnotes

[1]In fact, one of the pathbreaking studies in the economic analysis of petroleum did estimate a number of simple price-quantity equations; see M. A. Adelman, The Supply and Price of Natural Gas (Oxford: Basil Blackwell, 1962).

[2]Economic theory states that both the quantity supplied and the quantity demanded of a commodity are related to the price of that commodity. However, only an 'ex post' time-series of observations on the quantity that cleared the market and the associated price is available. This leaves one in the predicament of not being able to say whether an estimated simple relation is the demand or the supply schedule, if either. This is commonly referred to as the 'identification problem'.

More specifically, identification means that if the errors, exogenous variables, and endogenous variables in a function are known, the structural parameters are uniquely determined. Whether a system is identified is not a matter of cleverness in specification but concerns the true nature of the model. To orient the reader, the process of model building consists of three distinct issues: (i) mathematical completeness, (ii) identification of the parameters, and (iii) statistical estimation of the parameters. Each issue must be handled satisfactorily before going on to the next.

As it turns out, this identification problem can be resolved by the application of prior knowledge. In the case of the Alberta oil market, one can assume that demand was determined largely exogenously. For the period since the mid-fifties, when the major pipeline extensions to eastern markets were completed, this seems to be a reasonable presumption. Even before that time, the operation of various prorationing devices (regulated by the industry itself before 1950, and by the government thereafter) meant that the market price was not determined through the joint interdependent operation of demand and supply.

[3]The traditional economic theory of supply and demand assumes such things as perfect competition, profit maximization, perfect knowledge and instantaneous equilibrium. These may or may not be valid approximations of reality. Beyond this, as the theory recognizes, changes in the price of oil are not wholly explanatory of changes in the quantity supplied; any factor that affects the marginal cost of oil production is also relevant. These include: prorationing regulations, input costs, the extent of fixed inputs, marginal taxes, and changes in technology. Also the quantity of crude oil supplied is subject to economic conditions in the markets for other ('joint') products, such as natural gas.

[4]In theory, the outputs of any of these other tasks could be sold in the marketplace, as on occasion they are; however, even in these cases the value of the output is derived from its expected contribution to crude petroleum production.

[5]The final stage of production, 'operation' or 'lifting', involves the application of variable inputs to existing development equipment to bring petroleum to the surface, and preliminary transportation and processing (i.e., separation). The final product, then, is petroleum 'at the field gate'. Somewhat more narrowly we might consider petroleum 'at the wellhead'. More broadly, we might look at petroleum f.o.b. at a central gathering point, for example, natural gas at the Alberta border, or crude oil at the Edmonton terminal of the Interprovincial Pipe Line. In each case a different physical product (product and location) is implied, and a different set of total inputs required.

[6]An issue that deserves further elaboration is the role of 'land' as a factor of production. Insofar as cost is concerned, the 'reservation price' of land must be derived almost entirely from expected conditions in the petroleum market. The price of mineral rights, then, is not a payment to bring land into the petroleum industry from other profitable uses; it is a payment to bring the land into the industry now rather than later. The supply of mineral rights is perfectly inelastic: the payment in such a case can be expected to be 'price-determined' rather than 'price-determining'.

[7]Costs are defined in economic terms to include any required allowances for risk taking. The discount facter in the present value calculations reflects the required return on capital employed.

[8]P. Davidson, "Public Policy Problems of the Domestic Crude Oil Industry" American Economic Review 53 (March 1963) and S. L. McDonald, Petroleum Conservation in the United States: An Economic Analysis (Baltimore: The John Hopkins Press for Resources for the Future, Inc., 1971) argue that there are three potential foregone revenues (user costs) which commonly result from producing an extra barrel of oil today instead of tomorrow: (i) the basic user cost of one less barrel in future inventory, (ii) the fraction of all future barrels lost due to damage to the primary drive, and (iii) the fraction of that barrel that could be lost due to 'common property' considerations when the rule of capture applies (the last is a negative user cost which induces more rapid recovery of oil). The rule of capture is the legal provision which states that oil belongs to the party which brings it to the surface; hence, in a shared petroleum reservoir, the holder of the mineral right is not given clear ownership rights to the oil the ground.

Chapter 2

A CONCEPTUAL MODEL OF OIL SUPPLY

This chapter draws upon the framework already outlined to elaborate upon the economic analysis of oil supply, with specific reference to Alberta.

The industry will again be discussed in terms of three different levels of activity: operation, development, and exploration. These will be examined in this order, although counter to the actual chronological order of activities, since the expected profitability in exploration depends upon expected conditions in development and operation; the profitability expected in development depends upon expected operating conditions; in the operation decision the development and exploration expenditures represent sunk investments.

2.1 Operation

Consider a particular petroleum reservoir, developed with some configuration of well-spacing, pumping, gathering and separating equipment. The operating decision can be described as the selection of the depletion path for the reservoir which maximizes the company's present value profits. This profit maximizing output path obviously depends upon 'technical' factors (the volume of oil in place, reservoir characteristics, and the nature and vintage of installed capital equipment), 'economic' factors (the prices of inputs and outputs now and expected in the future), and 'political' factors (prorationing and tax regulations). If we assume a particular set of price and cost expectations, the modelling task is that of incorporating the technical and regulatory constraints in an appropriate manner. A more detailed examination of these two factors follows.

2.1.1 Technical Considerations

The possibility of lifting oil from a particular reservoir is constrained in two ways--by the physical characteristics of the reservoir, and by the amount and type of capital equipment in place.

For reservoir i in time period t, the various possible levels of output (at capacity) of oil and gas can be represented by the function $g(O, G)$. Output is produced by the services of capital (K),

the remaining oil in place of the reservoir (R), and all other inputs (L), which are related to the output levels by the function, h (L, K, R). The ensuing production function relationship for the joint product process can then be written as:

$$g_t\,(O_t^1,\ G_t^1) = f_t\,(L_t^1,\ K_t^1,\ R_t^1) \tag{1}$$

Further, it seems reasonable to assume that the individual operator producing at capacity has little ability to vary the proportions of the products in any one period: that is, proportions are fixed in the short run, so we can speak of a single product which we will call oil.[1]

$$O_t^1 = f_t\,(L_t^1,\ K_t^1,\ R_t^1) \tag{2}$$

In this case, the law of diminishing returns usually assumed by economists implies:

$$\frac{\partial O}{\partial L} \geq 0,\ \frac{\partial O}{\partial K} \geq 0,\ \frac{\partial O}{\partial R} \geq 0$$

and

$$\frac{\partial^2 O}{\partial L^2} \leq 0,\ \frac{\partial^2 O}{\partial K^2} \leq 0,\ \frac{\partial^2 O}{\partial R^2} \leq 0$$

That is, successive additions of a single input adds to output, but by progressively smaller amounts.[2]

The volume of oil in place (R_t^1) is obviously equal to the volume initially in place ($\bar{R}^1$), less output in previous years; or, symbolically,

$$R_t^1 = \bar{R}^1 - \sum_{j=0}^{t-1} O_j^1 \tag{3}$$

where j represents years of past production. Substituting into equation (2) we can then write,

$$O_t^1 = f_t(L_t^1,\ K_t^1,\ \bar{R}^1,\ O_o^1,\ O_1^1,\ \ldots,\ O_{t-1}^1) \tag{4}$$

and expect that

$$\frac{O_t^i}{O_j^i} \leq 0; \; j = 0, \ldots, t-1.$$

In other words, production in an earlier period will reduce the ability to produce in the current period.

An expression like equation (4) may be viewed as the way in which the economist summarizes the relevant technological factors governing oil production. The major analytical hurdle is to move from the general theoretical presumption that such a relationship exists to the representative functional form. This transition is contrained both by the difficulty of developing a simple model based directly on the complicated principles of reservoir engineering, and by the absence of readily available data in most instances.

2.1.2 Political Considerations

The company's production decisions are constrained not only by nature but also by the regulatory environment.[3]

Some regulations impinge directly on the production function: for example, pollution control provisions may prohibit certain types of technological practices, or force the use of greater quantities of inputs.[4] Likewise, prorationing and well spacing regulations directly limit the quantity of output. Other regulations affect the relative value of inputs or outputs: royalties, drilling incentive schemes, and earned depletion allowances are examples. Changes in any of these types of regulations can be expected to alter industry behaviour.

Although individual regulations will not be examined, several broad classes will be noted.

(a) Production control[5]

In general, market demand regulations have prevented companies from lifting as much oil as they might have liked; ostensibly they were designed to offset the costs of the 'rule of capture', though they were not perfectly efficient in doing so.[6] In rather simplistic terms, a regulatory constraint may be appended to the production relations described earlier (Equation 4). Let $O_{t,m}^i$ be the market-demand 'allowable' for the reservoir, and let $O_{t,c}^i$ be the 'capacity' output in the absence of the prorationing regulations.

$$\text{If } O^i_{t,c} \leq O^i_{t,m},\ O^i_t = f_t(L^i_{t,c}, K^i_t, R^i, O^i_o, \ldots, O^i_{t-1}) \qquad (5)$$

$$\text{If } O^i_{t,c} > O^i_{t,m},\ O^i_t = O^i_{t,m} = f_t(L^i_{t,m}, K^i_{t,m}, R^i, O^i_o, \ldots, O^i_{t-1})$$

Prorationing affects both the output path of the reservoir and the inputs used to produce the oil.

A number of complications make simple handling of prorationing difficult. Profit maximization depends not only on the current market demand restrictions but expected future restrictions as well. Therefore, companies must forecast future market conditions and the future prorationing regulations. At the same time, prorationing may somewhat reduce uncertainty about the existence of market opportunities, since it guarantees sales for all oil producers. The basis on which the market demand allocations have been set has varied over time.[7] So, although one can speculate that the more stringent the market demand prorationing restrictions the more a particular reservoir's output tends to be shifted into the future, quantifying this shift is very difficult.[8]

(b) Tax regulations

(i) Royalties[9]

A royalty is a payment assessed for the use of a good or service to which some other party retains legal ownership. Thus, mineral rights are legally owned by the Crown in most of Alberta, but the right to produce petroleum is passed on to companies which in turn commit themselves to make a payment to the legal owner for every unit of mineral produced.

It should be noted that the royalty is a gross royalty, assessed on the market value of oil without regard for the costs of production. Its essential effect, then, is to reduce the netback value of oil to the producer at the wellhead.

(ii) Income tax regulations

The corporate income tax is a combined federal-provincial tax, ostensibly designed to fall on the 'profits' of the industry. The provisions are complex, but it is clear that variations in these tax regulations can be expected to affect the profitability of different ventures. Three major elements are important in quantifying this effect. The first is the manner in which costs, specifically capital

costs, are treated. Second is the presence of special allowable deductions or subsidies, such as the depletion allowance or Petroleum Incentives Program. Third is the tax rate itself.

Since we are presently concerned with the operating decision alone, investment decisions and the tax implications therein can be ignored for the moment.[10]

In conclusion, profitability will rise as prorationing allowables are increased, as royalty rates are reduced, as tax regulations are liberalized, and as depletion allowances are increased.

The overall operating decision can then be summarized in the following manner:

Objective: To maximize profit, defined as
the present value of revenues (net of royalties)
minus the present value of operating costs
minus the present value of taxes (other than royalties)

Subject to: Production function restrictions
Fixed reserves and capital equipment
Expected prices, costs and taxes
Prorationing regulations

Profits are maximized by selecting the optimal levels of output over time and the optimum quantities of variable inputs.

2.2 Development

Development obviously precedes operation. The previous section has examined how operation is best scheduled, given a particular level of development. Of course, operating expectations are an essential part of the development evaluation decision. Development is the process of installing equipment in a deposit of petroleum in order to allow the products to be brought to the surface. It involves a fixed stock of oil-in-place and, therefore, could be expected to show diminishing marginal returns to capital, both in the primary stage of production and also in moving from primary to enhanced recovery systems. Development expenditures involve effects on three critical variables: the inital output level possible from the equipment, the pattern of production decline in output as the reservoir is drained, and the date of abandonment of the pool.

Primary recovery normally refers to the production of oil by natural flow or simple pumping, possibly with gas injection. More wells, or larger wells and pumps, may both increase access to oil in the ground and speed up the rate of oil recovery. At the same time, diminishing returns to capital investment can be expected to result from at least three sources: a greater number of wells will create more well interference, reducing the average well productivity in the current period; additional wells will tend to be located in less attractive parts of the reservoir; and faster recovery may impair the reservoir's natural drive, significantly reducing the future producibility of the reservoir. (The last effect is controlled in practice by maximum production rate limitations established by regulatory authorities.) If we restrict ourselves once again to the single product oil, abstracting from joint product considerations, we can specify the general nature of the development decision in much the same way as in the previous section.

The objective is to maximize profits, subject to expectations of future prices and costs, within the government regulatory environment, and subject to some production function. The production function is one which exhibits eventually diminishing marginal returns to inputs, and it has one fixed input (the volume of oil in place).

Again, the vital question, apart from that of data availability, is the precise nature of the production function. Presumably the basic production function would be the same as that underlying the operation decision, but with the capital input factor variable.

Enhanced recovery operations are schemes which significantly increase the total recovery of oil by increasing the natural productive forces of the reservoir. (The term enhanced recovery is used in this study to cover both 'secondary', e.g., waterflood, and 'tertiary' recovery schemes.) From an economic point of view the quantity of output per period can be increased, but at the cost of using more purchased inputs. Enhanced recovery can be expected to raise the current production level; in addition, it generally reduces the reservoir's decline rate, and extends the producing life.

2.3 Exploration

Exploration is the process of locating new deposits of petroleum; as such, it provides a number of major contrasts with the operation and development decisions above. Three, in particular, must be noted.

First, the 'technological' uncertainty is several degrees removed from that of development or operation; exploratory risk, the possibility of large expenditures with no resultant commercial finds, is significant. Secondly, the joint product problem can be assumed away only with grave injustice to reality: exploration, including dry holes, yields information relevant to finds of both oil and gas, and companies clearly have some ability to deliberately vary the proportions of these products found. Thirdly, the production function relationship for exploration is necessarily different from that for development and operation in the individual pool.

At the same time, it is often suggested that the basic production function characteristics are similar to those discussed above: various inputs of labour and capital may be applied to a quantity of oil-in-place which is fixed by nature in order to generate output (i.e., 'discovered reserves'). One would expect that this production function too exhibits (eventual) diminishing marginal returns to increased inputs. The production of crude oil, of course, stems from the additional activities of development and operation, as discussed above--therefore a firm's evaluation of the potential profitability of any exploratory prospect presumes some production scheme for any successful venture.

Once again, the major difficulty comes in specifying the precise nature of the production function relationship for the exploration phase. A number of studies have essentially ignored this problem by building models which relate exploratory results solely to economic stimuli without explicit recognition of a production function relationship.[11] Conversely, others have simply extrapolated past physical results in a purely statistical manner without explicit consideration of the nature of the underlying behavioural processes or the impact of economic variables.[12] Several more recent studies, however, have attempted to tie exploratory activity directly to production function characteristics.[13]

The remainder of the study concentrates upon the exploration process for crude oil in Alberta, keeping in mind the framework already formulated.

Footnotes

[1]Over the longer run, it may be argued that the products can be lifted in variable proportions, through such actions as positioning wells in different parts of the reservoir, or reinjecting natural gas for the purpose of pressure maintenance (this latter example is better considered as a type of capital investment; the gas is 'purchased' at its opportunity cost to be injected into the reservoir). The producer may also be able to alter the composition of the end product through some flexibility in the type of separation equipment employed.

Aside from the considerations above, which involve conscious decisions on the part of the operator, it is quite likely that the relative shares of the products will vary over the life of the reservoir; if this is a natural (uncontrolled) occurrence it will not affect the production function formulation used here, but will, of course, affect the price of the output.

[2]A reservoir will exhibit diminishing marginal returns if there is an attempt to raise the current level of output by (i) using existing equipment more intensively, with a given amount of reserves and capital equipment, or (ii) by adding more equipment to existing reserves. This 'law' is really a hypothesis about the nature of the production function.

[3]For a more detailed exposition on recent regulations and their effect on industry return, see W. B. Friedenberg, Z. C. Slagorsky, and A. J. Walsh, "Government Incentives in Canada's Petroleum Industry" (Calgary: Canadian Energy Research Institute, March 1980), Working Paper 80-1. A brief review of major tax regulations affecting the Alberta petroleum industry from 1947 through 1978 is given in Appendix A of this study.

[4]Consideration of pollution suggests that the production of any good is a joint product process--some waste inevitably results.

[5]For a review of Alberta production control schemes and their implications, see G. C. Watkins, "Proration and the Economics of Oil Reservoir Development, Province of Alberta," Research thesis (University of Leeds, 1971).

[6]The rule of capture is a particular aspect of the common property problem referred to above, in footnote 8 to Chapter 1. (Disproportionate ownership may accrue to the operators pumping most quickly from a shared reservoir.)

[7]In Alberta, for instance, allowables were allocated on a per well basis prior to 1964, but on a reserves basis since; individual wells were granted a basic allowable with different formulations from 1950-1957, from 1957-1964, from 1964-1972 and since 1972; and discovery wells have been treated differently at different times.

[8]For estimates of the impact of the various Alberta schemes on a number of reservoirs, see G. C. Watkins, "Proration and the Economics of Oil Reservoir Development, Province of Alberta," Research thesis (University of Leeds, 1971). Also, by the same author, "Conservation and Economic Efficiency - Alberta Oil Proration," Journal of Environmental Economics and Management, 4 (March, 1977), pp. 40-56.

[9]For an excellent historical description of royalty regulations with respect to most petroleum products, see A History of Crown Rentals, Royalties and Mineral Taxation in Alberta to December 31, 1972, (Edmonton: Alberta Energy and Natural Resources, March 1977), Report No. 1.

[10]Many other taxes are included directly in the cost of inputs (for example, import duties, excise taxes, etc.) so need not be considered separately. They may be judged relevant if a social rather than private perspective is taken. Land rentals are also a matter of some importance, particularly on large tracts of land held for exploratory purposes. This study does not discuss the taxes assessed under the National Energy Program of 1980.

[11]Some examples are, E. W. Erickson and R. M. Spann, "Supply Response in a Regulated Industry: The Case of Natural Gas," Bell Journal of Economics and Management Science 2 (Spring 1971), and P. W. MacAvoy and R. S. Pindyck, The Economics of the Natural Gas Shortage (Amsterdam: North Holland, 1975). Of course, both recognize the theoretical importance of the production function concept.

[12]For instance, M. K. Hubbert "Energy Resources" in Committee on Resources and Man National Academy of Sciences--Natural Research Council, Resources and Man (San Fransisco: W. H. Freeman and Co., 1969).

[13]Proponents of this methodology include R. S. Uhler, Oil and Gas Finding Costs (Calgary: Canadian Energy Research Institute) Study No. 7, September 1979, and D. N. Epple, Petroleum Discoveries and Government Policy (Massachusetts: Ballinger) 1975. The most ambitious attempt to build up an economic exploration model from the underlying physical parameters (while recognizing the probabilistic nature of the problem) is that of Gordon Kaufman: See, for example, G. M. Kaufman, W. Runggaldier, and Z. Livne, "Predicting the Rate of Supply from a Petroleum Play," Working Paper No. MIT-EL 79-001 WP (MIT Energy Laboratory, January, 1979): E. Barouch and G. Kaufman, "Probabilistic Modelling of Oil and Gas Discovery" in Energy: Mathematics and Models, SIAM Institute for Mathematics and Society, 1976; and E. Barouch and G. Kaufman, "Estimation of Undiscovered Oil and Gas", Proceedings of Symposium in Applied Mathematics, 21. This model has been applied, with very interesting results, to the North Sea: P. L. Eckbo, H. D. Jacoby and J. L. Smith, "Oil Supply Forecasting: A Disaggregated Approach," The Bell Journal of Economics, 9 (1); also M. A. Adelman and H. D. Jacoby, "Alternate Methods Oil Supply Forecasting" and P. L. Eckbo, "A Basin Development Model of Oil Supply" both in R. S. Pindyck (ed.), Advances in the Economics of Energy and Resources, Vol. 2, Jai Press, 1979.

Chapter 3

THE EXPLORATORY PHASE OF CRUDE OIL PRODUCTION: AN EMPIRICAL ANALYSIS

3.1 Introduction

We have seen that, from an economic point of view, petroleum companies are normally considered profit-maximizing entities. They operate in a particular legal and physical environment, one major aspect of which is the underlying geological distribution of oil reservoirs in the region. Given the current state of technology the companies are able to generate output by applying inputs such as capital equipment and labour to this physical setting; the rate at which inputs are applied is governed by the companies' objective of profit maximization.

The physical realities of petroleum occurrence enter this process in three distinct ways.

- There is the underlying actual distribution of oil in pools of varying size scattered through the region. This distribution cannot be known with certainty.
- There is the exploration company's expectations about the underlying distribution of petroleum. These may differ from the actual distribution and vary between companies.
- There is the distribution of deposits of discovered oil. This is the main source of information with which to characterize the actual unknown distribution, but it must be remembered that the discovered deposits are drawn from the underground population on the basis of deliberate decisions by companies in light of their expectations.

Of these three 'types' of distributions of oil in the ground, only the latter is directly observable. However, it is inevitably subject to measurement difficulties, because of uncertainty about the exact nature of discovered deposits, limitations in the extent of publicly available data, (e.g., due to lags in the release of data on exploratory wells), and problems in analysing the data that is available. A full model of exploration activities in a region would necessitate a consideration of all three manifestations of the physical distribution of petroleum.

3.2 The Investigative Unit

Any quantitative petroleum supply inquiry must initially adopt a unit of analysis upon which to focus research activity. Four rational and distinct alternatives present themselves. From the largest to the smallest conceptually, they are: aggregated geographical regions (like countries), broad geological basins, specific exploratory plays, or single well sites. The former is the overriding concern of governments, while the latter is of particular interest to the individual firm. The focal point of this study will be specific exploratory plays.[1]

A petroleum basin or area the size of Alberta will in general contain reservoirs or pools with distinctly different geologic characteristics. We shall regard the totality of pools in Alberta as being classified into a collection of subpopulations of pools of similar geologic type; these subpopulations we shall refer to as plays. By definition, a play begins with the exploratory well that discovers the first pool in a subpopulation of pools. Thus there are, in principle, as many potential plays as geologic types. Implicit in this definition is the distinction between the physical extent of the formation and the commercial extent of the play. Admittedly, there are geographical coordinates delineating the known areal extent of a play, but that area is incidental to the underlying geological structure.

To set the purely physical environment to which we shall be referring, Figure 3.1 presents a simplified geological cross-section of Alberta. Seven oil-bearing formations, or plays, are denoted: Cardium, Viking, Nisku, Leduc, Beaverhill Lake, Keg River and Granite Wash. (The term Leduc is used to describe what is often labelled the D-3 formation, and the term Nisku is used for the D-2.)

To discern the relative importance of these particular geological horizons see Figure 3.2. As indicated there, the majority of Alberta crude oil reserves are attributable to a relatively small number of plays: the three largest comprise 55 and 64 percent of the total estimated oil-in-place and recoverable reserves respectively; all seven selected formations yield 72 and 87 percent.

A historical sketch of the discovery of these plays, an indication of their geographical location, and a detailed review of reserve appreciation on a play-by-play basis, is presented in Appendix C.

An in-depth statistical examination of the properties of discovered reserves on a play-by-play basis is undertaken in Appendix B.

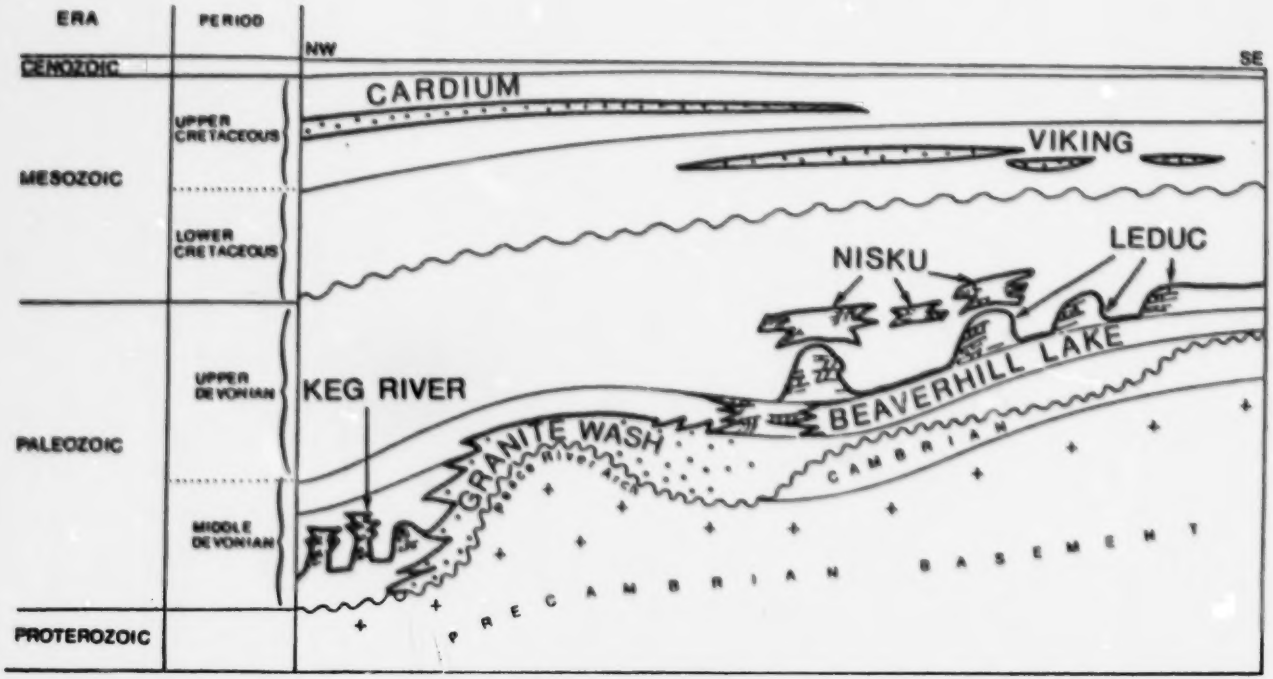


Figure 3.1: Simplified Geological Cross Section of Alberta Showing the Seven Plays

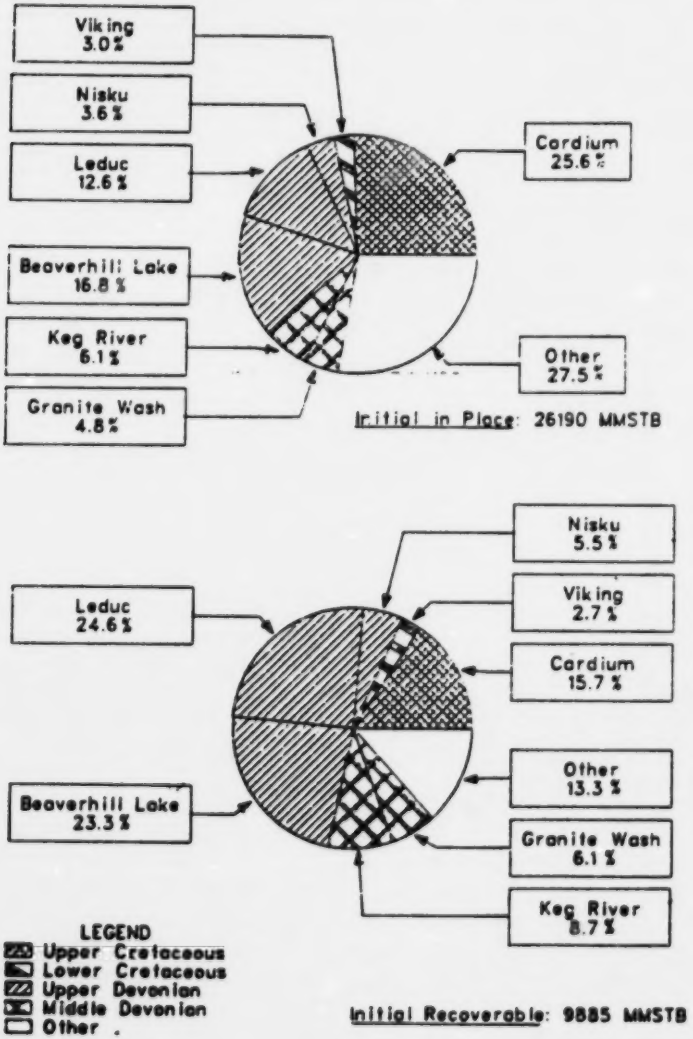


Figure 3.2: Geological Distribution of Proved Reserves of Crude Oil, Alberta, 1976

The most important observations from those statistical tests can be summarized as follows:

- Different oil plays do indeed have distinct characteristics.
- The timing of discovery of pools within a play is not random, with the larger pools (in surface area and reserves) tending to be found first.
- The reasonableness of accepting a highly skewed distribution of pools by size within any oil play is confirmed.
- For physical reservoir attributes measuring size (area and oil volumes), the mean value for already discovered pools is not an appropriate estimate of the expected value for a new success.

These observations suggest that oil exploration companies do have some ability to differentiate between underground structures prior to drilling. The direct implication is that exploration can best be treated as a non-random process. From that perspective, the discovery process is related to:

- the underlying distribution of oil pools (number, size and location); and
- the knowledge of the industry.

This knowledge is of two types, which may be interrelated: some ability to distinguish productive deposits from dry locations, and some ability to distinguish larger productive deposits from smaller.

3.3 General Methodology

Ordinarily, the petroleum inventory of a particular region can be augmented either through positive revisions and extensions in discovered pools or through new discoveries of reserves. Throughout this study the focus will be on the discovery process, although some mention will be made of the appreciation of existing reserves.

The 'discovery process' is a descriptive label for the sequence of information-gathering activities (e.g., surface and seismic surveys) and acts (drilling of exploratory wells) that culminates in the discovery of petroleum deposits. In building models of the discovery process, we will regard it as being effectively described by a small number of quantitative attributes and postulated relations among them. Although doing descriptive injustice to the way in which geologists

extrapolate geologic facts to guide exploratory activity, a model composed of such relationships can embody many of the essential features of the discovery process.

It has been decided to utilize a relatively pragmatic modelling approach, in which a flexible equation-form is fitted to data on the discovery process for crude oil in different oil plays. The form of the equation allows for the tendency to find larger reservoirs first, with ensuing sharply diminishing returns to exploratory effort. However, it is flexible enough that identical reactions are not forced on all oil plays--both the underlying geological distribution of crude oil and the technical ability of the companies to determine the most favourable drilling locations will obviously vary from play to play.

More specifically, the model postulated herein consists of three conceptually distinct parts. The first portrays the general economic environment for exploratory activity; the second allocates this aggregate activity amongst plays; and the last might be called a technological relationship between drilling effort and the volume of oil discovered. These three types of relationships, along with their hypothesized determinants, are summarized below. The main focus of the study, and the analysis of this chapter, relates to the third of the relationships.

Model Components

Behavioural Relationships:

(i) aggregate exploratory effort = f (expected profitability)

(ii) play-specific exploratory effort = f (expected relative profitability relative to other petroleum plays)

Technological Relationship:

(iii) discovered reserves by play = f (play-specific exploratory effort)

3.4 Model Specification and Results

Obviously one factor underlying the decision to penetrate a particular formation in any year is the explorer's understanding of the technological relationship: based on historical results what is the reserve discovery expected from a given amount of drilling effort? To this, however, must be added other factors of relevance to a profit-oriented corporation--its expectations about the sales value of the oil and gas produced, the depletion profile of the reservoir, and the total costs of exploration and production. The purpose of the 'behavioural' type relationships is to capture the effects of these other variables.

The technological relationship will be discussed first, and in most detail, while the behavioral relationships are examined in Chapter 4.

3.4.1 The Reserves Discovery Equations

(a) General Description

The discovery of oil pools (containing oil-in-place, and potentially recoverable reserves) requires exploratory inputs. Most directly, exploratory wells must be drilled and the petroleum reservoir penetrated. Factors influencing exploratory drilling were discussed above; however, the results of that effort are limited by the actual distribution of oil in nature. It is hypothesized that a specific oil play exhibits diminishing marginal returns over time: that is, equal successive amounts of effort (numbers of penetrations to possible oil-bearing rock) bring progressively smaller discovery volumes. The presence of diminishing returns might be interpreted to reflect a variety of factors including:

- an ability by companies to select the best available locations (an ability which is imperfect, or no dry holes would be drilled);
- a tendency for larger pools to be found first, even in a 'random' drilling procedure (which would be true, for instance, if larger pools cover a larger area, so they are easier to hit than any small pool).[2]

The hypothesis can be expressed in simple conceptual terms as follows, where R_t represents the volume of oil discovered in year t in an oil play, and E_t represents the number of tests of the play's

geological horizon:

$$R_t = f(E_t, E_{t-1}, E_{t-2}, E_{t-3}, \ldots) \qquad (6)$$

We expect that a greater number of wells drilled to the formation in this year will generate higher discoveries, i.e.,

$$\frac{\partial R_t}{E_t} \geq 0,$$

but that greater effort in past years will mean fewer discoveries since there are fewer promising locations available and there is less likelihood that a large accumulation lies undiscovered, i.e.,

$$\frac{\partial R_t}{E_{t-i}} \leq 0.$$

Three issues must be addressed before the reserves discovery equation can be applied empirically: (1) the particular variables to which the model is applied, (2) the problems posed by joint products, and, (3) the specific functional form used in estimation.

(b) Dependent Variables

The dependent variable is the amount of oil discovered in a particular year in the oil play under consideration. However, one may view oil discoveries in a number of different ways, and there are numerous technical problems in estimating oil volumes. This study abstracts from the multitude of theoretical and practical problems of a geological and engineering nature, which arise when oil resources and reserves are estimated for a pool. Data from the Energy Resources Conservation Board (ERCB) have been used and are assumed to be reliable. The ERCB and oil companies normally record and estimate reserves only for those pools which are expected to be commercially exploitable, so that very small accumulations of oil in the play may go unrecorded. Further, different producers may have different cutoff values for abandonment of oil shows as 'dry'. Hence the data base may be somewhat weak insofar as low volume discoveries are concerned.

The volume of oil discovered may be measured as the volume-in-place, or as that estimated to be recoverable, with the latter commonly divided further into that recoverable by primary production techniques and that from enhanced recovery methods ('secondary' and 'tertiary' recovery). Three obvious candidates for 'oil discoveries' suggest

themselves: oil-in-place, primary recoverable reserves, and total recoverable reserves. This study has utilized the first two variables only; the decision to install an enhanced recovery (ER) scheme (secondary or tertiary recovery) depends very much upon the specific characteristics of the reservoir, the technology available at that time, and anticipated economic conditions and regulatory schemes. For most of the Alberta oil pools considered in this study, any ER schemes were adopted a number of years after the discovery of the pool. Hence it seems unlikely that the exploratory decisions of operators (to drill at specific locations) were much influenced by the anticipation of recoverable reserves which could be attained only through ER investments.

There is a high, but not perfect, correlation between oil-in-place and primary recoverable reserves. The ultimate interest of the operator is in profits from oil production, so that recoverable reserves are of prime interest; but it is not clear that this is the best variable to utilize in an exploratory model. Decision makers in oil companies have some ability to discern potential petroleum-bearing structures, but a larger structure may be more directly correlated with oil-in-place than with recoverable reserves since estimates of recoverable reserves depend upon economic, regulatory (e.g., tax) and technological conditions. Also, reserve estimates are subject to change for reasons entirely unforeseen by the petroleum exploration company.[3] Both oil-in-place and primary recoverable reserves have been used as the measure of exploratory success.

A final complication relates to the 'appreciation' of oil pools. A successful exploratory well finds an oil pool, but the size of the pool in total can be estimated with reasonable accuracy only when development activities have delineated the perimeters. Therefore, for oil pools other than very small ones, the estimate in the year of discovery of the quantity of oil-in-place is very much less than the actual content of the pool. If companies have any ability to distinguish better prospects from poorer, then it is the actual size of the pool which is of importance. Therefore, the volume figures used in this study are the estimates made in 1976; this allows considerable time for appreciation in the volume estimates for most of the pools considered--all except those found in the mid-1970s. For pools discussed recently, little time has passed for appreciation of reserve estimates. This poses potentially serious problems for the discovery equations estimated in this study. The hypothesis is that average discovery size will fall as the play progresses; however, the data utilized will include both this effect and any tendency for more recent

discoveries to be understated due to the exclusion of complete appreciation of resources. There are two reasons for supposing that the bias imparted to the discovery relationship will be relatively minor. First, in the plays except the Keg River and Cardium, very few pools have been discovered in more recent years, so that the strength of the depletion effect relationship is largely conditioned by pools in which considerable time for appreciation has been allowed, and by the complete absence of commerical finds more recently. Secondly, the smaller pools generally undergo relatively little appreciation: this seems to be confirmed by simple perusal of the tables on appreciation in Appendix C (Tables C.3a through C.22b). In the Keg River pools, for instance, even after ten to twelve years there is no positive appreciation for oil-in-place (in fact, reserves for many pools were lower than in the year of discovery); for recoverable reserves, the ten year's appreciation factor is only 10 percent (as compared to 760 percent for Beaverhill Lake and 550 percent for Leduc). Section C.3 of Appendix C provides some more detail on appreciation, including consideration of the possible bias imparted by using the 1976 reserve estimates for all pools.

Some studies of petroleum discovery have used dependent variables different to those used here.[4] For example the volume of oil discovered can readily be broken down into separate multiplicative components. Two commonly used are:

Oil discovered = average discovery size x number of discoveries

Oil discovered = average discovery size x number of exploratory wells drilled x exploratory well success rate

Equations can then be estimated for these separate components. This approach allows somewhat more flexibility in the influence of such factors as past exploratory activity (which might, for example, be hypothesized to affect the success rate differently than it affects average discovery size). Some results along these lines will be reported here, but the approach was not used extensively. In part this lay with difficulties in the variable 'number of discoveries', which is clearly a discrete variable, and--for separate oil plays in a small region like Alberta--tended to have low values, frequently zero. This posed problems in econometric estimation.

(c) Independent Variables

Difficulties also arise in selecting an appropriate independent variable. The suggestion has been that more exploratory drilling will tend to generate larger additions to reserves, but that the greater the drilling in the past the smaller the addition to reserves from any effort in this period. In fact, petroleum exploration uses a number of different inputs, and several different measures can be imagined to capture the 'depletion' effect of past activity.[5] This study draws on the assumption that each penetration of an exploratory well into a geological formation of interest (i.e., an oil play) is a test of that play; furthermore, once the initial major discovery in that play has been made, it is assumed that each penetration is of interest to the industry.

It was not, of course, possible to include as a separate variable the number of penetrations in each year prior to the year considered. (This would leave no degrees of freedom at all in estimation.) Accordingly, the study uses cumulative prior penetrations to the formation; cumulation starts with the year of the initial discovery, on the assumption that it was only then that serious and widespread attention focussed on that particular oil play. (Appendix D includes the basic information on the number of exploratory wells drilled in Alberta up to 1976, and the numbers of penetrations by such wells into the main oil plays in various parts of the province.)

(d) Joint Product Problems

Analytical analysis of petroleum industry activity is very much complicated by the fact that much of the industry's effort is not directed towards a single clearly defined objective. Two major difficulties exist. First, successful exploration may yield natural gas, rather than crude oil. Second, a single exploratory well passes through a large number of geological formations; the operator presumably has a specific formation to which he is primarily attracted, but other formations may be of interest, and it is not unknown for a formation which was initially dismissed to prove productive.

Our hypothesis derives from the presumption that oil companies are able, in part at least, to direct their attention to larger oil pools before smaller: the joint product problem says that our exploratory variable is not 'homogeneous'--not all penetrations are alike. Ideally, one would like to classify the penetrations by 'zone of intent' (although this still leaves unresolved cases in which several

zones were of interest); but such information is simply not available. Therefore, as in most joint product cases, it is necessary either to reformulate the problem as a multi-equation system including all the products involved, or to make some arbitrary (but, the investigator hopes, reasonable) assumptions to allocate activities between products. The former course is too unwieldy. (It would involve modelling all significant oil and gas plays in a joint-estimation model.) Therefore, some allocation assumptions have been required. Examination of Appendix D provides a rough basis for such allocation; it shows the geographical location and timing of exploratory wells, of oil and gas successes and of penetrations to various formations. The overlap of geological formations is not continuous over the province; this is reflected in the penetration counts (for example, there are no penetrations of the Cardium formation in southern, eastern and northern Alberta). Here the joint product problem does not arise. Three criteria for allocation have been considered. First, the oil plays are all geographically limited; this is clearly true in an ex post sense (from our perspective today) as can be seen in the maps in Appendix C. It is realized early in many oil plays that the presence of an oil deposit at a particular location requires more than just the occurrence of the formation of interest. For example, the Beaverhill Lake formation extends widely throughout the province, as can be seen in Table D.11; however, geologists were able to argue early in the life of the play that the deposits of oil in the play were associated with the formation of reefs in the shallow sea areas along the edge of the Peace River arch in the Upper Devonian period. Second, interest in natural gas in the province can be seen to exhibit a geographical and temporal bias, relative to oil. That is, certain areas of the province are more 'gas-prone' and other areas more 'oil-prone' (Table D-4 presents some simple statistics in this regard; it shows the ratio of oil successes in exploratory drilling to gas successes, for 28 areas of the province, and for years up to 1976.) Non-associated gas deposits predominate in the foothills area, the south and east of the province (much of the oil here is heavy oil, in plays other than those considered) and in the Peace River area immediately adjacent to the B.C. border. Also, the number of gas discoveries increased sharply in 1970 (particularly in the eastern part of the province); among other factors, this reflects anticipated improvements in gas selling prices, increased competition in the purchase of natural gas and expected growth in gas markets. Third, shallower formations will often be penetrated as explorers aim for deeper formations of interest. (For example, in regions 27 and 28 a large increase in the number of penetrations of the Beaverhill Lake

formation can be seen after the first finds in the Keg River formation in 1965 in the Rainbow-Zama areas. Penetrations of the Viking and Cardium formations rose significantly in 1970 with the shift in emphasis toward natural gas.)[6]

The seven major oil plays under discussion will now be considered.

Cardium. The Cardium formation is the 'shallowest' (youngest) of the formations considered. It does not, however, extend throughout the entire province. Moreover, north of the Pembina field, the formation continues north but without any appreciable thickness of sandstone (until close to B.C. north of Grande Prairie). Therefore the area of real interest to the oil play extends from areas 9 through 23 (see Figure D.1 and Table D.9 in Appendix D). A rise in penetration starting in 1969 is evident; this coincides with the rise in natural gas strikes. However, areas 11, 12, 13 and 19 through 23 compromise almost all the Cardium penetrations and none of these areas except 12 show major gas successes, so that no modification for the oil/gas joint product problem seems to be required. Overlap of formations is more likely to be important, given the geographical overlap of the plays considered. However, the main area of penetration of the Cardium play does not, on examination, overlap too severely with those of the other major plays. (The Leduc and Nisku plays were largely to the east, and the Beaverhill Lake to the north.)

Viking. The Viking formation is also a shallow one and is very widespread, including the gas-prone southeastern part of the province. Moreover, the Viking play overlaps the Cardium (note the rise in wells in areas 11, 12 and 13 starting in 1953), the Beaverhill Lake (area 25 in 1957) and the Leduc and Nisku formations. Given the pervasive spread of the Viking formation, the wide area in which Viking pools lie and the relatively minor significance of the Viking oil play, it is difficult to see what adjustments to make to penetrations to accommodate joint product problems.

Nisku. The Nisku formation is also widespread, apparently somewhat more so than the more important Leduc; however, petroleum bearing reef structures in the two Upper Devonian strata appear to be related, and occur in several north-south ridges in central Alberta. Therefore, it does not seem possible to separate the influence of the Leduc play. A comparison of penetrations by region suggests that overlap with other oil plays may not be so significant. (That is, areas of major significance for the Cardium and Beaverhill Lake plays--regions such as 12, 13, 22 and 25--were not the most important ones for the Nisku play.) A rise in penetrations in 1969 may correlate with the increased

interest in natural gas. (While the Nisku formation is an 'old' one, it is not very deep through most of central Alberta; given the relative ease of drilling in the Prairies, an exploratory well with prime intent at a shallower formation--eg., a gas prone one--could quite easily be drilled deeper to the Nisku, or below.)

Leduc. The same general comments hold as for the Nisku play. The Leduc play has been treated as a single one, although one reviewer noted that it consists of at least three separate north-south ridges, so might be further divided.

Beaverhill Lake. This formation is found over much of the province, but as noted above the oil pools are found in reef structures in a rather small area in central Alberta (northwest of Edmonton). This corresponds to areas 20 and 22 through 27 (Appendix D). The major joint product problem relates to area 27, which covers the southern part of the Keg River play and shows a large increase in wells commencing in 1964. (There is a jump also in 1956, which was the discovery date of the first Granite Wash pool in area 27.)

Granite Wash. This play involves a relatively small number of pools (15) in the north-central part of the province along the edge of the Peace River arch. The main influences on penetrations in this area are from the Beaverhill Lake play (starting in 1957) and the Keg River play (in 1964).

Keg River. This play is centred in the Rainbow-Zama areas of the far northwest of the province, and began in the year 1965. While some gas finds have been made (many before 1964 felt the area was gas-prone), the main interest has been in crude oil. The relative isolation, and the lateness of the play, suggest that joint product problems may be relatively minor.

(e) Form of Estimating Equation

The general hypothesis to be tested can be illustrated by a very simple diagram (Figure 3.3).[7] The horizontal axis shows the number of penetrations to a formation in year t, and the vertical shows the oil reserves found; a positive relationship is expected between the two variables (more exploration may add to oil volumes, but cannot reduce them). The exact nature of the penetration/discovery relation will vary from year to year, however; it is hypothesized that more activity tends to involve a 'depletion' effect, so that any given level of activity in a later year will yield smaller reserve additions. In graphic terms, this implies that the discovery curve (labelled

t) will shift down and to the right (for example, to curve t + n).

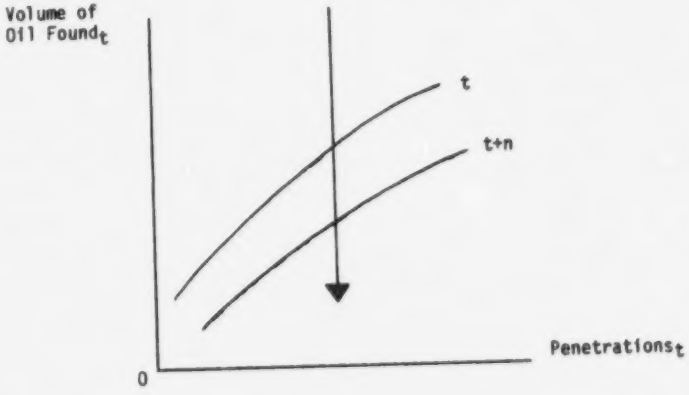


Figure 3.3: Oil Discovery Curves

There is a major problem in empirical estimation. Without a full theory of the underlying distribution of oil and the decision-making procedure of the industry, it is not possible to specify a precise form for the relationship between the three variables (discoveries in year t and the two independent variables--penetrations in year t and cumulative penetrations before year t). One might therefore try a variety of functional forms, 'fishing' for one which fits; given the plethora of options available and a little ingenuity, something could undoubtedly be found for any oil play. Of more interest, however, is the hypothesis that different oil plays follow a similar pattern, so that a common functional form can be fitted. In this regard, it seems logical to search for an estimating equation which allows for a strongly non-linear negative effect of depletion of the stock of pools on discoveries. (There is a great deal of evidence that the size distribution of oil pools is very heavily skewed, with a large number of small pools, and small number of large pools. As Appendix B

shows, the assumption of log-normality in the size distribution of oil reserves is reasonable for a number of Alberta oil plays. If larger pools are found first, then the oil volumes from incremental exploration will show sharply diminishing returns.)

A general functional form which incorporates such an effect is:

$$Res_t = \quad Pen_t \quad \exp. \quad Cum\ Pen_{t-1}$$

or

$$\ln Res_t = \quad + \quad \ln Pen_t + \quad Cum\ Pen_{t-1} \qquad (7)$$

It is anticipated that will be positive, and that will be negative. is the elasticity of reserves with respect to an increase in penetrations in this period. measures the effect of past penetrations on current discoveries. The equation is a simple one, and has the practical advantage of being mixed log-linear.[8] Such simplification comes at a cost of course; for example, a constant elasticity of reserves to penetrations is implied, as is a negative exponential effect of cumulative discoveries.[9]

(f) Results

Nine Alberta oil plays were considered. With the exception of the Cardium play, the estimating equation (for which results are reported in Table 3.1) was equation 7, above. Oil discoveries were measured in barrels. Three parameters were estimated: is the constant in the equation; is the elasticity of discoveries with respect to penetrations in that year and shows the percentage change in oil found with a one percent change in the number of wells penetrating that formation; shows the 'depletion' effect or the size of the change in reserves discovered this year as cumulative penetrations to the formation in prior years is higher. In the case of the Cardium formation one additional variable was included in some of the equations estimated, with a coefficient of ; this was a dummy variable with a value of zero in all years except 1953, the year of discovery of the Pembina pool, when it was assigned a value of one. (Pembina is by far the largest pool ever found in Alberta and, as Table C.12b in Appendix C makes clear, is many times larger than the next largest pool in the Cardium play.) Penetrations were measured by the number of exploratory wells drilled into the formation as shown in Appendix D; several

TABLE 3.1

RESERVES DISCOVERY EQUATION: REGRESSION RESULTS

A. OIL IN PLACE

Play (and year of first discovery)	Estimated Volume of Oil (millions of barrels)	Number of Pools	a_0	a_1	a_2	a_3	R^{2b}	D-W
Cardium (1953)	9,142	59	8.0184	2.3998	-0.00474*	7.7742	0.14	1.29
			(0.63)	(0.74)	(-1.8b)	(1.35)		
2 Cardium			8.73	2.06	-.0030		0.04	
			(0.69)	(0.63)	(-1.0b)			
Beaverhill Lake (1957)	6,136	20	17.140*	0.51996	-0.01682*		0.53*	1.94
			(1.74)	(0.20)	(-4.61)			
Leduc, D-3 (1947)	4,554	71	15.407*	1.5355*	-0.00867*		0.67*	1.65
			(4.57)	(1.72)	(-7.53)			
3 Leduc			12.072*	0.3643	-0.00521*		0.95*	
			(6.75)	(0.79b)	(-20.14)			
Keg River (1964)	3,525	407	6.273	3.0549*	-.00291		0.58*	
			(1.06)	(2.7b)	(-1.17)			
3 Keg River			8.350*	1.1143*	-.00257*		0.84*	1.11
			(4.19)	(3.08)	(-3.43)			
Nisku, D-2 (1947)	1,281	58	3.1404	3.2973*	-0.00248*		0.34*	2.47
			(0.46)	(2.18)	(-3.48)			
2 Nisku			6.72	2.419	-0.0020*		0.16	
			(0.91)	(1.46)	(-2.65)			
3 Nisku			7.2379	0.9832	-.00134*		0.72*	
			(1.87)	(1.19)	(-7.65)			
Viking (1949)	1,124	39	5.7343	1.5214	-0.00058		0.02	1.85
			(0.37)	(0.49)	(-1.10)			
Granite Wash (1956)	161	15	17.9864*	-2.0385	-0.01756		0.10	2.62
			(4.49)	(-1.34)	(-1.311)			
Slave Point (1958)	134	9	0.78766	1.9490	0.00097		0.00	2.20
			(0.15)	(1.66)	(0.70)			
Sulphur Point (1967)	31	13	11.831	0.61324	-0.00566		0.12	2.65
			(1.04)	(0.39)	(-0.67)			

TABLE 3.1 (Continued)

B. RECOVERABLE RESERVES

Play (and year of first discovery)	Estimated Volume of Oil (millions of barrels)	Number of Pools	α_0	α_1	α_2	α_3	R^{2b}	D-W
Leduc, D-3 (1947)	2,262	71	16.511*	.99111*	-0.00891*		0.71*	1.78
			(5.37)	(1.72)	(-6.49)			
3 Leduc			12.388*	0.1238	-.00601*		0.84*	
			(3.35)	(0.13)	(-11.25)			
Keg River (1964)	1,099	407	6.525	2.7592*	0.00320		0.60*	1.12
			(1.20)	(2.72)	(-1.40)			
3 Keg River			8.149*	0.9415*	-.00299*		0.86*	
			(4.43)	(2.82)	(-4.32)			
Beaverhill Lake (1957)	1,000	20	19.610*	0.65982	-0.01479*		0.55*	2.12
			(2.43)	(0.32)	(-4.95)			
Cardium (1953)	966	59	1.0122	3.4651	-0.00396*	9.5008*	0.20	1.07
			(0.10)	(1.33)	(-1.94)	(2.04)		
2 Cardium			2.51	2.93	0.00218		0.03	
			(0.24)	(1.08)	(-.93)			
Nisku, D-2 (1947)	559	58	4.9649	2.6347*	-0.00248*		0.36*	2.51
			(0.80)	(1.94)	(-3.86)			
2 Nisku			7.35	2.047	-.00215*		0.20*	
			(1.09)	(1.35)	(-2.88)			
3 Nisku			5.095	1.3033	-0.00171*		0.82*	
			(1.33)	(1.58)	(-9.84)			
Viking (1949)	173	39	4.1920	1.6794	-0.00063		0.01	1.95
			(0.29)	(0.60)	(-1.42)			
Granite Wash (1956)	43	15	15.125*	-1.1705	-0.01952*		0.14	2.55
			(4.78)	(0.98)	(-1.84)			
Slave Point (1968)	24	9	2.3409	1.4520	0.00081		0.08	2.15
			(0.60)	(1.60)	(0.77)			
Sulphur Point (1967)	3	13	16.006	-0.22922	-0.00632		0.03	2.53
			(1.63)	(-0.19)	(-1.00)			

* Significant at the 5 percent level.

NOTE: The form of the equation estimated is as follows: (where t is the year in question and ln is the natural logarithm of the variable): ln (oil discovered$_t$) = α_0 + α_1 ln (penetrations$_t$) + α_2 (Cumulative Penetrations$_{t-1}$). The t-statistic is included in parenthesis below the estimated regression coefficient.

[a]A dummy variable was included for the Cardium play to capture the unusually large size of the Pembina pool (in 1953).

[b]This is the adjusted value of R^2.

modifications were made in these numbers to allow for the joint product problems discussed above.[10]

Table 3.1 summarizes the regressions, including results for both oil-in-place and estimated primary recoverable reserves. The plays are listed in descending order of size (based on 1976 volume estimates). The regression coefficients are shown, with the 't-statistic' in parenthesis below; an asterisk (*) indicates a coefficient which is significant at the 5 percent level. Also shown are the squared correlation coefficient (R^2) as an indication of the overall strength of the regression equation and the Durbin-Watson statistic (D-W) as a measure of the importance of serial correlation (auto-correlation). The α_1 coefficient is expected to be positive, while the α_2 should be negative.

For several of the plays, the results of more than one regression are reported. The additional equations are of two types. The results labelled 2 Cardium and 2 Nisku show the effect of increasing volume estimates in the final ten years (1967-1976) by the average appreciation facter for the play; in addition the Cardium results exclude the observation for 1953 (i.e., the Pembina pool). As Appendix C shows the Cardium and Nisku are the two major plays in which significant appreciation is likely of the reserve and oil-in-place estimates for recent discoveries. The results labelled 3 Leduc, 3 Nisku and 3 Keg River are based upon moving averages of the variables. (The Nisku data are the appreciated volumes.) As would be expected given the inherent uncertainties of oil exploration, the year-by-year series for discoveries shows great variability and moving averages might help to smooth out some of the random noise; as a result the statistical significance of the equations often appears improved (although this in itself is insufficient reason to use moving averages). More importantly, the case of moving averages is one way of minimizing the data deficiency for noncommercial finds, which are all reported as holding absolutely no oil. The annual data series therefore includes some observations with a zero value for discoveries; use of a moving average of appropriate length will eliminate these values, and the associated estimation problem. Of course, the discovery values will still be somewhat understated for some observations, but, unless there are a number of finds which are just barely noncommercial, the bias in the moving average series for discovery size should be minimal.[11]

The results are not fully compatible with the hypothesis, but seem supportive for four of the five major oil plays (Beaverhill Lake, Leduc, Nisku and Keg River). In the Cardium play, with unappreciated

reserve data, the coefficients have the expected signs, but only the cumulative penetrations variable is significant. However, if the Pembina pool is excluded, and recent finds increased to allow for possible appreciation, the postulated relationship is not statistically significant. These results, and those for Viking, may relate to difficulties in modelling a shallow play; deeper wells will penetrate these formations, and occasional finds will be made, even though the prime intent of exploration is quite a different geological stratum. Nor are results satisfactory for the three remaining deeper formations (Granite Wash, Slave Point and Sulphur Point), but none developed into major plays or involved many discoveries. It can also be seen that the significance of the relationship is lessened for the Nisku play if discovery values are appreciated in more recent years to allow for possible increases in estimated pool size. Also of interest is the importance of the statistical treatment of noncommercial finds, as indicated in the Leduc, Nisku and Keg River results. Not only are the correlation coefficients higher for the equations using moving averages (as would be expected) but the regression coefficients of both the current penetrations and cumulative penetrations variables become smaller (in absolute value terms). This direction of change in the coefficients was also found as the number of barrels of oil credited to years with no discoveries was increased (from 10 to 10,000 barrels, all clearly noncommercial volumes). Therefore, while a significant exponential decline effect seems to hold within the main plays, precise estimation of the size of this effect may be critically affected both by the likely future appreciation of reserve estimates in recent discoveries, and by the actual volumes of petroleum in 'noncommerical' finds; unfortunately neither of these problems is readily resolvable. (Of course, the problem of unprofitable discoveries is somewhat different with respect to oil-in-place and recoverable reserves; in the former case there may be physical volumes of oil present which are unrecorded, while in the latter the major problem is that the lowest possible 'reserves' value greatly exceeds one, and that the critical minimum value will change with changing economic and technological conditions.)

An extension to the analysis will now be summarized, briefly. The main hypothesis of the analysis has been that as a play proceeds and a greater proportion of potential oil-bearing traps in the formation is tested, volumes of oil become harder and harder to locate. The volume of oil discovered can also be considered in a 'decomposed' manner, as the number of pools discovered multiplied by the average size of a discovered pool. Therefore, the tendency to falling oil

volumes can be related to a declining size of discoveries and/or to a declining number of pools discovered.[12] Table 3.2 includes results of regression equations relating average discovery size to the number of cumulative penetrations. It shows that for the same four major plays (Leduc, Nisku, Beaverhill Lake and Keg River) there was a definite 'depletion' effect on average discovery size; the larger the number of previous penetrations to that play the smaller the average discovery size. (For the Pembina play, the regression coefficient has the correct sign, but is not quite significant at the 5 percent level.) There was no significant effect on average discovery size from the number of wells drilled in that year.[13,14]

3.4.2 Conclusion and Implications

The immediate aim of exploration is the production of valuable knowledge--knowledge about the location of profitable deposits of crude oil. The statistical data assembled in this study illustrates that for several of the major Alberta oil plays there is a common pattern of development. The large additions to reserves came early in the life of the play, and as the cumulative number of 'samples' of (penetrations to) the formation rose, the volume of new oil found became smaller and smaller. At the same time, several of the oil plays did not exhibit this tendency: the negative exponential effect was not found in several of the smaller oil plays, nor in the Cardium play, once the giant Pembina pool was excluded, and allowance made for possible appreciation of recent finds. In these plays, it appears that the predominant effect is not the decline in large pools undiscovered as the play progresses; rather, it may be very difficult to distinguish better from poorer prospects. In this case, the main limit on the development of the play would simply be the reduction of the unexplored area underlain by that geological formation.

Obviously physical depletion of the remaining undiscovered volume of oil in a formation is inevitable; this study offers some support for the common observation that the depletion process exhibits regularity of a negative exponential nature. The study also found some support for the suggestion that falling discoveries can be related both to a falling number of discoveries and to a decline in the size of the average discovery made.

It may be of interest to examine the implications of these results for continual exploratory activity in Alberta. Since the results relate to industry activity up to 1976, it is also possible to look at the actual results of more recent oil exploratory activity in

TABLE 3.2

AVERAGE DISCOVERY SIZE REGRESSION RESULTS

A. OIL IN PLACE

Play	Average Discovery Size (millions of barrels)	α_0	α_1	α_2[a]	R^2[c]	D-W
Cardium	155	9.8286* (6.27)	-0.00395 (-1.98)	5.9924 (1.43)	0.22*	1.29
Beaverhill Lake	307	11.43* (7.14)	-0.01583* (-4.84)		0.54*	1.82
Leduc	64	12.807* (15.18)	-0.00772* (-6.85)		0.61*	1.27
Keg River	9	13.458* (8.36)	-0.00578* (-3.79)		0.53*	0.59
Nisku	22	10.10* (8.61)	-0.00219* (-3.10)		0.23*	2.17
Viking	29	6.7877* (4.50)	-0.00053 (-1.09)		0.01	1.88
Granite Wash	11	6.08* (3.31)	-0.02006 (-1.55)		0.06	2.60
Slave Point	15	1.9235 (1.13)	-0.00135 (0.96)		0.00	2.03
Sulphur Point	2	7.5112* (2.29)	-0.00645 (-1.50)		0.12	2.37

TABLE 3.2 (Continued)

B. PRIMARY RECOVERABLE RESERVES

Play	Average Discovery Size (millions of barrels)	α_0	α_1	α_2[a]	R^2[c]	D-W
Leduc	32	11.919* (16.16)	-0.00796* (-8.08)		0.69*	1.45
Keg River	3	12.119* (9.24)	-0.00553* (-4.46)		0.61*	0.62
Beaverhill Lake	50	9.4003* (7.32)	-0.01336* (-5.10)		0.57*	1.95
Cardium	16	6.9883* (5.55)	-0.00279 (-1.74)	6.6324 (1.97)	0.26*	1.04
Nisku	10	8.9388* (8.70)	-0.00219* (-3.53)		0.28*	2.25
Viking	4	5.5576* (4.51)	-0.00057 (-1.42)		0.04	1.99
Granite Wash	3	5.2391* (3.76)	-0.02066* (-2.10)		0.15*	2.53
Slave Point	3	1.2777 (1.01)	-0.00110 (1.03)		0.00	1.92
Sulphur Point[b]	-	3.9513 (1.71)	-0.00342 (-1.8)		0.03	2.63

* Significant at the 5 percent level

NOTE: The form of the equation estimated is as follows:[a]

$$\ln(\text{Average Discovery Size}_t) = \alpha_0 + \alpha_1 (\text{Cumulative Penetrations})_{t-1}$$

[a]The Cardium play includes a dummy variable with a value of one in the year 1953.
[b]Less than 500,000 barrels
[c]Adjusted R^2.

the province to see if they correspond to the results of the study. Table 3.3 includes two parts. Part A is based on material in the 1982, Reserves Report, Alberta Energy Resources Conservation Board, and includes summary information on oil discoveries since 1976 in the oil plays examined in this study. (The 1982 report is based on reserves as estimated at December 31, 1981; it includes reasonably complete data for pools discovered up to 1980, but no allowance has been made for further appreciation of volumes in these recent finds.) Only the Cardium, Viking, Keg River and Nisku plays showed more than three discoveries over the four year period, and three of these plays had the smallest average discovery size. (The Keg River play, the youngest, exhibited the highest average discovery size.) The Keg River and Cardium plays account for 78 percent of the total primary recoverable reserves in the eight plays.

Part B of Table 3.3 makes use of Table 3.1 to show the total volumes of oil implied by the estimated regression equations if there were 100 penetrations per year in the various formations. No results are reported for the Granite Wash or Slave Point formations, since the regression equations were insignificant here and coefficients did not have the expected signs. Table 3.3 does show estimates for the Viking play, since the coefficients had the expected sign, but it must be emphasized that they were not statistically significant at the 5 percent level.

Slave Point, Sulphur Point and Granite Wash. The model failed to yield satisfactory results for these formations. All three are small--they have relatively little oil and a small number of reservoirs. As a result, none have developed into major oil plays. Therefore, many of the penetrations to these formations must be regarded as directed largely to other targets, and the failure of this model to capture the exploratory results is not surprising.

Cardium. The direction of influence of variables corresponded to that predicted, but the overall explanatory power of the hypothesis was quite limited (as evidenced in the low correlation coefficients). In part the explanation may lie in the impossibility of determining exploratory effort deliberately directed towards a specific oil play; in the case of younger shallower formations this problem is particularly acute. Furthermore, when allowance was made for appreciation of recent discoveries, the negative exponential relationship for discoveries was not significant. In fact, if 300 wells were drilled into the Cardium formation and each discovered the average number of barrels per penetration recorded in that play (exclusive of the Pembina pool), a total of about 343 million barrel of oil-in-place would be

TABLE 3.3

ALBERTA OIL DISCOVERIES, 1977 - 1980, 8 plays

A. Actual Discoveries

Oil Play	Number of Pools	Volumes of Oil (000 bbl.)			Average Primary Recoverable Reserves Per Pool (000 bbl.)
		In-Place	Primary Recoverable	Enhanced Recovery	
D-3, Leduc	2	8,023	805	0	403
D-2, Nisku	6	6,110	837	0	140
Viking	28	59,355	6,022	0	215
Cardium	62	272,333	24,108	4,411	388
Beaverhill Lake	1	9,439	472	1,888	472
Keg River	16	81,688	28,387	0	1,774
Granite Wash	2	7,033	1,580	0	790
Slave Point	3	15,732	4,858	0	1,619

B. Implied Discoveries with 100 Penetrations per Year

Oil Play[a]	Historic Penetrations Per Year (number)		Implied Oil Volumes (000 bbl.)	
	Average[b]	1976	Oil-In-Place	Primary Recoverable
Leduc, D-3	43	29	134	23
Nisku, D-2	97	47	243	71
2 Nisku			624	137
Beaverhill Lake	42	20	4	70
Keg River	120	14	39,914	8,684
Cardium	62	76	373	157
Viking[c]	198	202	51	17

[a]The name of the play given refers to the equation used in Table 3.1.
[b]Over the life of the play from the initial discovery to 1976.
[c]The regression coefficients for the Viking play were not significant but had the anticipated signs.

found. (Three hundred penetrations over four years corresponds approximately to the 1976 drilling rate.) This exceeds the actual reported discoveries by about 25 percent, but is much closer to the actual than the very low figure in the estimated regression equation, and recent actual discoveries have not been fully appreciated. This suggests that discoveries in the Cardium formation are governed largely by the overall extent of the geologic horizon and some difficulty in pinpointing promising drilling sites, rather than a pronounced tendency to declining discovery size.

Viking. The estimated regression equations were not significant for the Viking play; this has been taken, in large measure, to reflect the shallowness and widespread occurrence of the Viking formation. (From 1949 through 1976 there were almost 5400 penetrations to the Viking formation; the Nisku formation had only 2844 and the next highest, the Cardium and Keg River, about 1450 each.) The Viking play is the least productive of the six main plays. As with the Cardium play, the prime determinant of the discovery rate may be the areal extent of the play; recent discoveries have been very small on average, but a significant number of discoveries still occur each year.

Nisku. The 'average' oil pool discovered prior to 1976 in the Nisku play yielded about 10 million barrels of primary recoverable oil. From 1977 through 1980 a further six pools were found, with an average size of only 140 thousand barrels. This is somewhat more than the regression equations would suggest.

Leduc. The Leduc formation along with the Keg River was described in the most satisfactory manner by the reserves discovery equation utilized in this study. (Given the inevitable uncertainties in exploration, correlation coefficients of 0.70 are very satisfactory.) From these results, the depletion of the stock of undiscovered oil appears pretty well complete for the Leduc play, as evidenced by Table 3.3. If 400 penetations were to yield only 23,000 barrels of recoverable reserves, the economic viability of continued exploration directed to that geological horizon would have to be questioned! In fact, more oil than this was found, but in only two pools.

Beaverhill Lake. The extrapolations of Table 3.3 suggest that the play is pretty well exhausted. This, too, corresponds with the opinion of most geologists. It can be seen that the equation for oil-in-place exhibits a more pronounced depletion effect than that for primary recoverable reserves. (This may reflect the narrower spread of recovery factors for Beaverhill Lake pools than for pools in other plays.) In fact, one significant discovery has been made in this formation since 1976.

Keg River. The hypothesis that a depletion effect makes discoveries progressively more difficult was supported in the case of the Keg River play.[15] Table 3.3 points out that even in the Keg River play discoveries have fallen off rapidly as cumulative exploration rises. That this may be so is suggested by the relatively small number of actual penetrations to the Keg River play in 1976. At the same time, the regression equations do suggest that significant volumes of undiscovered oil remained in the Keg River play after 1976. As Part A of Table 3.3 shows, there were relatively large volumes of primary recoverable reserves discovered from 1977 through 1980; the average pool size in the Keg River pool exceeded that of any of the other seven plays.

This section of the chapter has considered the discovery of crude oil reserves in Alberta in a play-specific framework. For four of the major oil plays, the results are encouraging; there does appear to be a similar progression through the plays, from relatively large, and many, discoveries through a natural depletion to smaller reserve additions, until exploration directed to that particular play no longer appears to be economic. This historical progression does not apply to the Cardium or smaller oil plays, nor does the method provide information of use in assessing the discovery of entirely new oil plays. It does appear that the estimated regressions tend to understate the potential of the major plays to some extent. Given the very small average discovery size in most plays in recent years, this may reflect the fact that the input data on discoveries tended to be biased in the downward direction, insofar as small (noncommercial) finds are concerned. The rise in real oil prices in the 1970s may have reduced the minimum economic size for oil pools, with the result that some of the discoveries from 1977 through 1980 would have been recorded as noncommercial, if discovered earlier.

The following chapter will consider several other aspects of the reserve addition process, including the 'behavioral' relationships related to exploratory effort.

Footnotes

[1]The emphasis on oil plays, as well as the general relationship between discoveries and exploratory effort owes much to the work of J. Ryan: "An Analysis of Crude-Oil Discovery Rate in Alberta" and "An Estimate of the Conventional Crude-Oil Potential in Alberta," Bulletin of Canadian Petroleum Geology, Vol. 21 (2), 1973.

[2]R. S. Uhler, "Costs and Supply in Petroleum Explorations: The Case of Alberta," Canadian Journal of Economics IX (February 1976) and "Forecasting Petroleum Supply: Methods and Aggregation Bias" in The Economics of Oil and Gas Self-Sufficiency in Canada (Calgary: University of Calgary Division of Continuing Education, 1975) has noted that the existence of 'learning-by-doing' will offset the tendency to diminishing discoveries. As the play progresses companies learn more about the underlying geology, and so may be able to place wells in better locations.

[3]The Energy Resources Conservation Board operates under the following definitions: "Reserves will be identified as being in place or recoverable, with reserves in place defined as the total resource in a deposit less any portion of it deemed unrecoverable by any foreseeable technology or under any foreseeable economic circumstances; and recoverable reserves defined as the reserves considered recoverable under current technology only, and present and anticipated economic conditions." The definitions suggest that even oil-in-place estimates could be revised due to technological or economic changes (i.e., of an unforeseen nature); the average primary recovery factor for Alberta light and medium oil pools is only 22 percent, and the primary plus enhanced factors only rarely exceed 70 percent, suggesting that modifications in the oil-in-place values for these reasons are likely to be extremely rare. The quotation is from pages 2-3 of the 1976 Reserves Report of the ERCB; in that report only 14 pools out of the more than 700 in the province showed a total recovery factor of 70 percent or more.

[4]F. Fisher, Supply Costs in the U.S. Petroleum Industry: Two Economic Studies, Johns Hopkins Press, 1964, and E. Erickson and R. Spann (1971).

[5]R. S. Uhler, Oil and Gas Finding Costs (Calgary: Canadian Energy Research Institute, 1979) found significant substitution possibilities between various inputs. To capture a 'depletion' effect, one of the following variables might be used, instead of that utilized here: cumulative prior exploratory footage, cumulative prior reserve additions or cumulative prior number of reservoirs found. K. D. Foat, Oil Supply: A Play Oriented Model (unpublished M.A. thesis, University of Calgary, 1979), tested these measures for three Alberta oil plays, but found no apparent improvement on the measure used in this study.

[6]Generally speaking, the major geological formations which developed into Alberta oil plays are not the geological formations which made up the major non-associated natural gas plays. (There are natural gas pools in the oil play formations, of course, and significant volumes of associated gas.)

[7]A similar graph is used by Uhler (1975). Uhler (1976) provides a formal rationalization of a general equation form similar to that used here, based on assumed statistical distributions of underlying stochastic variables.

[8]Uhler (1976) and Foat used a similar but slightly more complex form of equation 7, including the term $(\alpha_3 \quad CPen^2_{t-1})$: this allowed for a more pronounced nonlinear effect of past activity, and also allowed for increased knowlege to more than offset the depletion effect in early days of an oil play (i.e., $\alpha_2 > 0$, and large enough to offset a negative α_3, in the early days of a play).

[9]The antilog of α_0 might be taken as an approximation of the size of the first discovery in the play. (That is, when $Pen_t = 1$ and $Cum\ Pen_{t-1} = 0$.) One major statistical problem arose with the use of this equation in that in some years for some plays there were no discoveries; a zero value can not be included in logarithmic form in an estimating equation such as (7) if ordinary least squares techniques are to be used. The difficulty is not necessarily that absolutely no oil was found, but that very small (noncommercial) finds are unrecorded. For 1976 it may also reflect time lags in reporting discoveries. The main results reported in this study have arbitrarily set discoveries in a year in which a zero is reported at one [thousand barrels). It is of some importance to note that the cut off between commercial and noncommercial finds is not independent of prevailing economic and regulatory conditions.

[10]The major modification can be summarized as follows, for the various plays. The Keg River, Slave Point and Sulphur Point values were unaltered. The changes for the other plays were as follows:

Cardium: Included areas 9-23 (see Figure D.1 in Appendix D).

Viking: Areas 2-4 and 9-26. In areas 25 and 26 the number of penetrations was reduced by about 80 percent each year in the years 1957 through 1965 to allow for the great increase in drilling activity associated with the Beaverhill Lake play. In areas 2, 3, 4, 9, 10 and 13 through 18 penetrations after 1969 were reduced to allow for the large increase in gas-directed efforts.

Granite Wash: Area 27, with a reduction in years from 1965 through 1972 to allow for the Keg River play.

Nisku, D-2: Areas 3, 4, 9, 10 and 12 through 27 with a reduction for years after 1969 to allow for gas-directed activity.

Leduc, D-3: Same as Nisku, D-2.

Beaverhill Lake: Areas 20, 22-26.

[11]We are grateful to Walter Haessel for encouraging us to apply the moving average approach. (The Durbin-Watson statistic is not relevant is this case.) At his suggestion we also estimated equations including a dummy variable for years with zero discoveries; the correlation coefficients were high and significant, as might be expected. However, we found these results hard to interpret since: (1) it is not clear that zero discoveries are an 'unusual' event, or that underreported discoveries are of identical size in years with no discoveries, so that the rationale for inclusion of a dummy variable was not perfectly clear; (2) this approach if used for conditional forecasts, would require an ability to determine years in which no commercial finds would be made.

[12]For a formal model along these lines, see Uhler (1976). For example, using the same symbols as in equation 2 in the text with N equal to the number of discoveries and ADS the average discovery size, one might hypothesize:

$$ADS_t = a\, e^{\alpha_1 (C\ Pen_{t-1})}$$

$$N_t = b\, Pen_t^{\alpha_2} e^{\alpha_3 (C\ Pen_{t-1})}$$

$$R_t = ADS_t \times N_t = a\, b\, (Pen_t)^{\alpha_2} e^{(\alpha_1 + \alpha_3)(C\ Pen_{t-1})}$$

or

$$\ln R_t = \alpha_0 + \alpha_2 \ln Pen_t + \alpha_4\, C\ Pen_{t-1}$$

This is the same as equation 7, but is now derived from two underlying hypotheses with α_2 (the coefficient of the $\ln Pen_t$ variable) equal to the elasticity of the number of discoveries with respect to penetrations, and α_4 equal to the sum of the separate depletion effects on average discovery size and number of discoveries.

[13]It can be seen from the equations in the previous footnote, $\alpha_4 = \alpha_1 + \alpha_3$. Estimates of α_4 are presented in Table 3.1 and of α_1 in Table 3.2. These results allow a 'residual' calculation of $\alpha_3 = (\alpha_1 - \alpha_4)$, the negative exponential effect of cumulative penetration on the number of pools discovered. For the five major plays, the following estimates of α_3 are obtained.

	Oil-in-Place Values	Primary Reserves Values
Leduc	-0.00095	-0.00095
Nisku	-0.00027	-0.00027
Pembina	-0.00079	-0.00117
Beaverhill Lake	-0.00099	-0.00143
Keg River	+0.00236	+0.00189

Several additional variables were included in the regression analysis, but exhibited no statistical significance.

One was a dummy variable to allow for the apparent shift toward natural gas discoveries following 1968. (If exploration shifted strongly to gas-directed effort many penetrations of the formations utilized in this study might have been in locations known to be unfavourable to oil.) It will be recalled (see footnote 10) that in the Viking, Leduc and Nisku formations an adjustment had already been made to the penetration variable.

A second variable incorporated, in equation 7, was cumulative penetrations squared; This variable had been utilized by Uhler (1976) and Foat (1979) and allowed for greater non-linearity in the reserves discovery relationship.

[14]An anonymous reviewer suggested that in light of the changing average size of discoveries as the plays progressed, it would be wise to test for signs of heteroscedasticity in the data. If heteroscedasticity is present, ordinary least squares regression techniques give results which are unbiased but also inefficient. Unfortunately tests for heteroscedasticity, and corrections, are usually difficult to apply. (For example, it is often suggested that a weighted least squares technique be used where observations are weighted by the reciprocal of the variance of the distribution associated with that observation; these are usually unknown.) As an indicater of the possible existence of heteroscedasticity we followed Walter Haessel's suggestion and ran several simple linear regressions with time as the independent variable and the squared deviation from the estimated discovery equation (equation 7) as the dependent variable. This was done for the results of the Cardium, Beaverhill Lake, Leduc and Nisku formations for oil-in-place; only in the Leduc equation was any indication of a time trend in residuals apparent, and there the R^2 value was only 0.24. This problem is discussed in many econometric books. See for example, Murphy, J. L., Introductory Econometrics (Homewood Ill: Irwin, 1973) pp. 298 - 307.

[15]Also, the Keg River play was the only one in which the regression results showed clear evidence of serial correlation, by the Durbin-Watson statistic. Hence the regression coefficients may be biased somewhat. The regression equations were rerun using the Cochrane-Orcutt technique to give the following results:

1) $\ln \text{Oil-in-place}_t = \underset{(2.16)}{11.551} + \underset{}{2.135} \ln \text{Pen}_t - \underset{(-1.60)}{0.0045} \text{Cum Pen}_{t-1}$

$R^2 = 0.71 \quad \text{D-W} = 0.82$

and

2) $\ln \text{Primary Reserves}_t = \underset{(2.30)}{11.337} + \underset{}{1.930} \ln \text{Pen}_t - \underset{(-1.88)}{0.0045} \text{Cum Pen}_{t-1}$

$R^2 = 0.75 \quad \text{D-W} = 0.81$

These equations give smaller reserve additions than those used in Table 3.3.

Chapter 4

EXTENSIONS TO THE ANALYSIS

4.1 Introduction

Chapter 3 focussed upon the 'technological' relationship in oil exploration. In the major Alberta oil plays strong evidence was found in support of the hypothesis of diminishing physical returns as the remaining undiscovered oil volume became smaller. The data base assembled for this study allows several extensions to the analysis. This chapter offers some preliminary evidence on a number of these issues, specifically:

- Can much be said about the sequence of exploratory plays?
- The actual volume of discoveries in any year is dependent upon the actual number of exploratory wells drilled; what determines the number of wells?
- The results thus far have been for oil-in-place, and primary recoverable reserves; do similar results hold for enhanced recovery reserves (secondary and tertiary recovery)?

4.2 Sequence of Oil Plays

The analysis undertaken supports the feelings of many analysts that the discovery process for petroleum tends to follow a negative exponential relationship. This study suggests that such a relationship holds within major exploration plays; the exploration play is a geologically natural unit of analysis. However, the results of the analysis, since they are play specific, say nothing about the overall discovery process in a region: this depends upon two additional factors--the sequence of major oil plays and the discovery of pools outside the major plays. It might be argued that the discovery process for the province as a whole should also show a negative exponential relationship; however, it is clear that the sum of a number of separate negative exponential relationships (with different estimated parameters and commencing at different dates) would not usually be another negative exponential relationship. Moreover, as just noted, the exploratory

play rather than the entire province seems to be the more sound unit of analysis, from a physical point of view.

One might, however, hypothesize that there is a sequence in the timing of major exploratory plays similar to that within a particular play, with the largest plays discovered first. Unfortunately, formal statistical analysis of such a hypothesis is virtually impossible for Alberta, since only six or seven major oil plays have been identified (leaving too few data points for meaningful statistical analysis). Table 4.1 includes data on these plays, taken from various parts of this study. The plays are included in the table in order of discovery from the first to the last.

No striking trends are immediately apparent; certainly a negative exponential technological relationship is not visible. Two further comments might be made. First, the time between major plays has been increasing. (If West Pembina is viewed as the next major oil play, it commenced in 1976, eleven years after the Keg River.) This suggests that, regardless of the size of the plays, a new play becomes harder to find as the industry matures in a region. This difficulty in finding new plays is confirmed by a more direct physical measure (in the column immediately after that showing the number of years between plays). The number of exploratory wells drilled in the province in the time between that in which the earlier play was discovered and that in which the next play was found has increased between successive major oil plays. Secondly, a possible geographic 'trend' might be noted in that the Beaverhill Lake play is somewhat more remote than the earlier four, and the Keg River is even more so. (Remoteness is defined in terms of the closeness to the Edmonton-Calgary axis in the south central part of the province.) This suggests that major plays in the more economically costly parts of the province tend to occur later.

The most recent oil play of major significance is the Devonian play associated with the West Pembina find. In the 1982 ERCB reserve report a total of 43 pools were reported, presumably those discovered up to the end of 1980. Oil-in-place was estimated at about 476 million barrels with primary recoverable reserves of 160 million and enhanced recovery reserves of 145 million. The average pool size was just under 4 million barrels of primary recoverable reserves. Despite the newness of the play, it would appear that it will provide less oil than any of the six plays shown in Table 4.1, except the Viking.

In conclusion, while the technological relationships examined in this study are of some value when applied to major oil plays in

TABLE 4.1

COMPARATIVE DATA ON ALBERTA OIL PLAYS LISTED BY DISCOVERY DATE

Play	Year	Years After Previous Play	No. of Exploratory Wells Since Previous Play	Total Volumes of Oil[a]		No. of Pools	Total[d] Acreage	Average Pool Size			Average[e] Depth
				In-Place	Primary Recoverable			Oil-In-Place[a]	Primary Recoverable Oil[a]	Acreage	
Rimbey, D-2	1947	-	-	1,281	559	58	135,000	22.0	10.8	2,331	5,593
Leduc, D-3	1947	0	-	4,554	2,262	71	202,000	64.1	39.6	2,840	6,220
Viking[b]	1949	2	132	1,124	173	39	266,000	28.8	8.0	6,815	5,291
Cardium	1953	4	773	9,142	966	59	736,000	154.9	30.2	12,479	6,562
Beaverhill Lake	1957	4	1,087	6,136	1,000	20	361,000	306.7	133.2	18,056	9,037
Keg River[c]	1965	8	3,091	3,525	1,099	407	N.A.	8.7	2.7	N.A.	N.A.

NOTE: Data are from various other tables in this study.

[a] In millions of barrels.
[b] No significant regression results were found for the Viking play
[c] Since input data for many of the Keg River pools were aggregated for pools discovered in a particular year, and attention was focussed on the reserves data, depth and acreage figures for this play are not available. Most of the Keg River pools lie at depths of 4,700-5,800 feet.
[d] Acreage is the sum of acreage covered by pools in the play, not the total acreage covered by the relevant geological formation.
[e] In feet.

Alberta, they can not readily be extended to an analysis of the sequence of plays in the province.

A second possibility suggests itself, for oil pools outside the major plays. Perhaps this 'residual' category itself exhibits a tendency to declining average discovery size, similar to that found in several of the major oil plays. Accordingly, Alberta oil discoveries outside the five major oil plays were estimated for each year from 1947 through 1976. (The oil reserves for the five plays came from the data base for this study, as reported in Appendix C. These were subtracted from the ERCB estimates of Alberta appreciated initial recoverable oil reserves by year of discovery, as reported in the 1976 ERCB Reserves Report. The ERCB provides data on recoverable reserves only, so no relationships could be tested for oil-in-place.) These values were then used as the dependent variable in a regression equation like those estimated in Chapter 3. (There it was argued that a greater number of penetrations into a play in each year will mean larger discovered volumes; but a larger number of cumulative penetrations means smaller discovered volumes, through the depletion of the remaining undiscovered resource base. In this case exploratory effort was estimated by the total number of exploratory wells less the number of penetrations in the five main plays.) No significant relationship was found for this residual group of oil pools.[1] There are some problems with the inputs to this regression equation. In particular, a variable such as residual oil discoveries can be expected to concentrate any errors in estimation of the underlying variables and so may be more subject to measurement error than the play-specific reserves estimates; furthermore, the measure of exploratory effort does not incorporate any allowance for the joint product problems, particularly the importance of natural gas and the fact that a well penetrates a large number of different geological formations.

However, the analysis does suggest that the process of exploration outside a major oil play is not subject to the same regularity and depletion effect as discoveries within a clearly defined major geological play. At least three underlying factors may be at work here.

- Some of the oil may lie in reservoirs completely outside any noticeable oil play. The oil may have been generated in this reservoir by some chance occurrence eons ago which was not often repeated in Alberta; or the oil may have been generated in a more common manner (e.g., in the same manner as that in one of the major Devonian reef plays) but a chance event caused the oil to migrate to the formation in which it is found.

- The oil might lie in a recognizable oil play, but the volumes of oil and number of pools involved may be so small that the general pattern of discovery hypothesized in this study never takes hold.

- Some of the oil included in this residual category may lie in an oil play which does follow the pattern suggested in Chapter 3, but in a play which was not selected for separate study.

However, the combination of the data from small plays of this sort will not generally yield a recognizable trend similar to that of the plays separately (unless the plays all occur at the same time and have identical features); nor will the distinguishing features of the play be revealed when combined with 'random' discoveries.

4.3 Exploratory Drilling Equations

4.3.1 Introduction

The analysis of Chapter 3 suggested that the exploratory play is a useful unit for economic analysis of the petroleum industry, and that there are certain regularities in the discovery process within a specific oil play. The actual time path of total oil volumes discovered is a function of both this technological discovery relationship and the actual timing of exploratory wells. (Obviously the two aspects are not independent. The willingness to undertake exploratory drilling in a particular year must reflect the expected physical results of that activity. The interdependence in the other direction is somewhat less direct; one aspect of it has been incorporated in the analysis of Chapter 3 with the inclusion of cumulative numbers of penetrations in the regression equations. As was suggested in that Chapter, more complex relationships can be hypothesized, including the effects of 'learning-by-doing'--the gradual acquisition of more knowledge about oil plays, and other improvements in the techniques of oil discovery, which are generated by the process of exploration.)

From an economic point of view, exploratory drilling is generated by expectations of economic profits. A formal model of the industry could be set up, based upon this behavioural premise. (For Canada, the main effort in this direction is that of Uhler. For the United States the work of Epple is of special interest. Models along this line have also been developed by Cox and Wright amongst others.[2]) Such formal models are very satisfactory from an aesthetic point of view, and offer a promising avenue for further research effort. However, it must be recognized that it is very difficult to formulate a

completely specified model which incorporates the major features of importance in the world as we observe it. Consider, for instance, the following complications: companies may not be simple profit maximizers, in particular they may be risk-averse to varying degrees, and thus act instead to maximize expected utility, where utility is a non-linear function of profits or depends both on the mean value and variance of expected profits; expected profits (utility) depend upon the particular experience, learning processes and attitudes of the company, and these will differ from company to company; the tax positions of different companies can vary significantly from one another; the decisions taken in any particular year will reflect the particular stock of capital inputs available in that year, and the elasticity of supply of variable inputs. The important point is not that such complications make impossible the construction of a useful formal model of the industry, derived from explicit assumptions about individual behaviour and technological relationships; rather, it should be emphasized that the construction of such model is a labour and time-intensive activity which normally involves comparison of a number of different simplifying assumptions to derive a specific model which appears to mimic reality in a reasonable way.[3] The approach taken here, in preliminary examination of the level of exploratory effort, is much more ad hoc. On the basis of initial presumptions and the results of both formal and informal models undertaken elsewhere, are there theoretically satisfying, statistically significant equations describing the level of exploration in various Alberta oil plays?[4]

The underlying premise that activity is governed by expectations of profit suggests the major variables which could be expected to affect the level of exploratory activity in the province:

- the anticipated selling price of the major products which might be produced (particularly crude oil and natural gas);
- the anticipated costs of drilling a well, completion of a successful well, installation of gathering and separation equipment, and operation of such equipment;
- the expected royalty and tax regulations;
- the size and reservoir characteristics of the expected oil and/or gas discovery;
- the likelihood of success in drilling an exploratory well; and

- the availability of financial capital, and anticipated return on other investment projects.

These variables could be measured in a variety of ways, and might be hypothesized to affect the level of exploratory drilling in a number of different ways. Several of the more common formulations have been examined.

The focus of this study has been the oil play, with emphasis on the number of penetrations to specific plays. The joint product aspects of this approach were discussed in Chapter 3; in particular, any single exploratory well may penetrate a number of geological formations of interest to the company, and both oil and natural gas are of interest. Two approaches to the consideration of the level of exploratory effort suggest themselves.

- The dependent variable, to be 'explained' might be the actual number of penetrations to a particular geologic formation (oil play). However, given the overlap of geological formations of interest to companies looking for oil and gas in Alberta, it must be recognized that the results of such an approach would overstate the number of exploratory wells drilled in the province.

- An alternative approach would be to utilize the total number of exploratory wells drilled in the province as a dependent variable in the analysis, and undertake a second set of regression equations designed to indicate what proportion of those wells actually penetrate a particular geological formation.

The remainder of this section of Chapter 4 will present some preliminary results utilizing the second of these approaches.

4.3.2 Aggregate Exploratory Drilling in Alberta

It has been argued, as is common in economic analysis, that petroleum industry behaviour is motivated primarily by expectations of profits (that is, revenues over and above all the variable costs of operation including a normal return to capital). It is common to recognize that behaviour may also be governed by the presence of risk or uncertainty, and the attitudes of firms towards risk, but even then anticipated profits are of importance. Table D.1, of Appendix D, shows the number of exploratory wells drilled in the province from 1947 through 1976, with a general upward movement apparent. Since the present study involved the collection of significant amounts of data

about the exploration for oil in Alberta, it was decided to test several common forms of an exploratory well drilling function, in order to see if they were supported by available data. Results have not been particularly satisfactory, as will be seen.

Reflection on two of the historical developments in the Alberta oil industry make the lack of good results for a simple exploratory drilling equation somewhat less surprising. As Table D.1 shows, the annual number of exploratory wells in the province generally grew from 1947 on, while over the same time period: (1) individual major oil plays tended to exhibit a definite depletion effect, with the average discovery size in the play falling as more wells were drilled, and (2) the real price of oil tended to fall at least until the early 1970s, as can be seen in Part 3 of Appendix A. Since both these factors suggest reduced profitability from oil, the rise in numbers of exploratory wells might be regarded as surprising. Of course, it is easy to find possible resolutions to this apparent inconsistency between industry behaviour and profit maximizing behaviour. For example:

- While the major single oil plays do show a depletion effect, it is not necessary that successive oil plays become smaller and smaller, so that the depletion effect within one play need not generalize to the province as a whole.

- It is not just the real price of oil which matters, but the profitability, so that reductions in taxes and/or the costs of drilling, completing and operating a pool could more than offset price falls.

- Technological changes at the pre-drilling level could make it easier to locate oil reservoirs, thereby reducing the cost of discovering a reservoir (presumably making the success ratio higher than it would otherwise be).

- Expected prices and average discovery size did not necessarily correspond to the actually observed values, and therefore may not have shown the same trend.

- The ability to drill wells in any particular year is constrained by some capacity limitations, above which costs rise extremely rapidly; hence the number of exploratory wells drilled in any year will be a function of existing drilling rig capacity, the ability to build more rigs in the short term, the ability to import rigs in the short term, and the desire to drill development, service, injection and other wells. Moreover, different types of wells (e.g., deeper wells as compared to shallower) may

face a different capacity limitation. To express the main point in slightly different terms--the number of exploratory wells the industry desires to drill may be unattainable due to shortages of drilling capacity.

- Crude oil is not the only valuable product from the Alberta petroleum industry; natural gas, in particular, is also significant (for example, the share of natural gas in the Alberta petroleum industry gross revenues was 5 percent in 1947, 8 percent in 1957, 17 percent in 1967 and 36 percent in 1977).[5]

- There may have been a significant rise in the number of companies active (and hence the degree of competition), and/or in the quantity of land available for drilling, and/or in access to financial capital.

It can be appreciated that it would be a very difficult task to build a formal model incorporating all the foregoing factors, since it would involve such components as geologically based models of both oil and natural gas prospects and discoveries, a model of the exploratory well drilling industry including technological changes and those factors which induce drilling rigs to enter and leave Alberta, a model of desired development and other well drilling, and a model of expectations formation for companies in the petroleum industry. Instead we have simply tested a number of basic relationships between the level of exploratory drilling and variables which theory suggests might influence it. Our purpose at this stage is to see if any particular relationships stand out as especially important, and to see if a relatively simple expression might serve as an adequate explanation of Alberta exploratory drilling, at least for aggregate modelling purposes. The independent variables were ones which have been found significant in earlier aggregate studies of the U.S. petroleum industry.

The most important underlying premises of the simple econometric approach were as follows:

- The real netback price (after royalties) is the most significant of the price/cost variables. Both oil and natural gas prices were included.

- Price expectations are directly governed by the current price for both oil and natural gas. These were assumed to be readily observable, and to represent expected prices. Thus, the independent variable for price was not an average of several past year prices, nor some projection of past prices nor the outcome of an expected market process.

- The average size of an oil or gas discovery in the previous year was assumed to be the most significant measure of the expected physical outcome from a successful well.

- The exploratory drilling relationship could be represented by a simple log linear regression equation.

As was suggested above, the results of these regression exercises were unsatisfactory. The general appearance of the results can be seen in the following equation derived from data for the entire province for the years 1948-1976.

$$\ln W = \underset{(10.40)}{7.83} + \underset{(3.65)}{0.67} \ln P_G - \underset{(-6.04)}{1.36} \ln P_O - \underset{(-1.62)}{0.06} \ln D_O - \underset{(-3.25)}{0.18} \ln D_G$$

$R^2 = 0.87$
D.W. = 1.72

where: W is the number of exploratory wells,
P_G is the real price of natural gas net of royalties,
P_O is the real price of oil net of royalties,
D_O is the average size of an oil discovery in Alberta the previous year, and
D_G is the average size of a gas discovery in Alberta the previous year.

While one might initially judge the overall statistical reliability of the equation and t-statistics to be acceptable, it is clear that the oil price and the discovery size variables have regression coefficients opposite in sign to those one might expect. The data obviously show a strong negative link between drilling activity and oil prices. This suggests that a simple single equation model of the sort tested here is unlikely to prove useful, despite the amount of manipulation done. The availability of a significant amount of data collected for this study did make for easy econometric 'fishing', and some was done (although as a matter of principle, this is not a desirable way to proceed). Despite this, and the lack of satisfactory results, a brief report on the general results may be of interest. First, it does not appear that the problem lies simply in the difficulty of obtaining a meaningful oil price series. The oil price variable retains its negative sign even if we use one of the price series for the value of oil in the ground, as estimated in Appendix A. (These prices make allowance for oil production costs and taxes other than royalties.) Secondly, it might be thought that a major problem the industry faced was in drilling the <u>desired</u> number of wells, given capacity limitations

in drilling rigs. This could call for a multi-equation model. Sometimes allowance can be made for this type of problem by including as an independent variable the lagged value of the dependent variable: this is common in stock adjustment models, where the actual activity in the current period is affected by current variables which determine desired activity, and last year's activity which reflects capability. Inclusion of this variable did not yield acceptable results, as can be seen in the following equation (where LW is the number of exploratory wells drilled last year).

$$\ln W = \underset{(6.12)}{6.43} + \underset{(2.71)}{0.52} \ln P_G - \underset{(-5.43)}{1.23} \ln P_O - \underset{(-1.03)}{0.038} \ln D_O - \underset{(-2.87)}{0.15} \ln D_G + \underset{(1.83)}{0.21} \ln LW$$

$R^2 = 0.88$
D.W. = 1.89

One other variable which has been found significant in some studies for the U.S.A. is the lagged value of the exploratory drilling success rate: that is, exploratory drilling would be affected not only by the prices of the products found and the average size of a success, but also by the likelihood of a success. However, in the simple single equation approach used here the success rate was not significant. Also not significant was a variable showing the ratio of allowable production under market prorationing regulations to existing wellhead capacity, designed to show the possible disincentive effect of such regulations. Finally, it seems likely that by the early 1970s, and possibly a little earlier, exploration companies were expecting major price rises, even though current prices were still constant or falling in real terms. Recourse to a dummy variable for these years does generate a significant regression coefficient with a positive sign and the coefficient of the oil discovery size variable becomes positive, but the oil price and gas discovery size coefficients remain negative. Moreover, the same conclusion holds if the data is run for the period from 1948 through 1968. Therefore, it would seem to be necessary to develop a more complex model to explain the total exploratory drilling effort in Alberta. That task is beyond the scope of this study, but the following issues seem to warrant more detailed attention: (1) the relationship between observed historical results and expected results, especially for prices and exploratory results; (2) the increasing importance of natural gas in the 1970s, and the effect of gas marketing problems; and (3) changes in the degree of competition over the period,

particularly in the access of smaller independents to financial capital and mineral rights.

We might, however, go on to ask whether we can say anything about the allocation of a particular level of exploratory effort to particular geological plays.

4.3.3 Exploration Equations for Different Oil Plays

Penetrations through a particular geological formation will be determined, in part, by the relative attractiveness of that formation as compared to other prospective geological targets. Other factors are important as well, such as the interest in deeper formations, and the number of exploratory wells drilled for general geologic knowledge, rather than with a specific target in mind. Moreover, the relative attractiveness of a specific formation depends upon the company's expectations about a wide range of technical, geological, economic and regulatory variables--expected discovery size, success rate, oil quality, well drilling and completion costs, market prices, taxes, conservation regulations, etc. However if the regulatory and economic expectations hold for all oil activities, the relative attractiveness of different oil plays can be seen to hinge upon the relative size of expected discoveries. A simple form of this hypothesis was tested for the nine Alberta oil plays examined in this study. Results are found in Table 4.2.

The dependent variable utilized was the ratio of the number of penetrations of that formation by exploratory wells in a particular year to the total number of exploratory wells drilled. Exploratory wells penetrate more than one formation, so may be counted more than once in the numerators of these values.

One independent variable utilized was the ratio, from the year before, of the average primary recoverable oil reserves from a discovery in this play to the average primary recoverable oil reserves in the province as a whole. (Appreciated reserves, as measured in 1976, were used.) This variable (called LRDS for lagged relative discovery size, in Table 4.2) was included in the regression equations in two ways: with the average discovery size in the province per exploratory well in the denominator ($LRDS_1$) and with the average discovery size in the province per oil success in the denominator ($LRDS_2$). In Table 4.2 the most attractive of these variables (as judged by the size of the correlation coefficient and significance of the regression coefficient) is reported for each play.

TABLE 4.2

PLAY EXPLORATION SHARE EQUATIONS: REGRESSION RESULTS

Oil Play	Constant (α_0)	Relative Discovery Size (α_1)		Gas Discovery Size (α_2)	R^2	Durbin-Watson
		$LRDS_1$	$LRDS_2$	GAD		
Nisku, D-2	.137*		.00019	.000012*	.20	0.67
	(3.89)		(1.47)	(2.00)		
Leduc, D-3	.057*		.00003	.000007*	.28*	1.55
	(4.09)		(0.64)	(3.12)		
Viking	.158*	.0116*		.000027*	.48*	1.38
	(2.49)	(1.89)		(4.51)		
Cardium	.034	.0061*		.000004*	.39*	1.80
	(1.72)	(3.13)		(2.06)		
Granite Wash	.005	.0018		-.000004	.19	1.86
	(0.68)	(1.90)		(-1.32)		
Beaverhill Lake	.002	.0063*		.000005*	.43*	1.61
	(0.08)	(2.98)		(2.83)		
Slave Point	.034		.0114*	.000011	.61*	0.73
	(0.73)		(2.51)	(0.24)		
Keg River	-.116		.0204*	.000086	.66	1.85
	(-1.90)		(4.06)	(1.96)		

NOTE: The equations estimated are of the form: Play exploration = $\alpha_0 + \alpha_1$ LRDS + α_2GAD.

*Significant at the 5% level.

A second independent variable was designed to capture some of the influence of gas-directed exploratory activity; it was the average size of a successful exploratory discovery of natural gas in the province (GAD in Table 4.2). This variable could have either a positive or negative sign, depending upon whether this and underlying formations were judged particularly attractive for natural gas; if they were, then a rise in the average discovery size of a gas well could be expected to lead to an increase in wells entering this formation.

A simple linear equation was estimated by ordinary least squares, linking each play with the relative size of a discovery in that play and the average size of a gas discovery in the province, for the years following discovery of the play.[6] These results are shown in Table 4.2 for all plays except the Sulphur Point, for which no relationship close to significance was found. The plays are listed in their order of discovery, and the table includes the regression coefficient for each of the independent variables, the t-statistic for each in parenthesis underneath, the squared correlation coefficient (R^2), and the Durbin-Watson statistic. As can be seen from the table, this approach does appear promising: in most of the plays a rise in the average discovery size in this play relative to the average discovery size in the province as a whole did mean an increase in the number of penetrations to the play relative to the total number of exploratory wells drilled. In several of the plays such an increase was also generated by a rise in the average discovery size for natural gas in the province. At the same time, the coefficients of determination (R^2) show that significant variation remains in all these equations and, by the Durbin-Watson statistic, several show actual (Nisku and Slave Point) or possible (Viking) autocorrelation. One reviewer pointed out that since these equations represent a share of each play in total exploratory activity, ordinary least squares techniques are not appropriate, and there are constraints on the values of the estimated coefficients. This was not necessarily so in the present analysis, since the formations considered do not exhaust all exploratory horizons of interest, and since wells often penetrate more than one geological zone of interest, so that the proportion of penetrations to formations added up over all formations would exceed one.

In conclusion, overall exploratory activity in the region may be determined largely by variations in aggregate industry conditions, such as average physical results in exploration, the general regulatory and tax environment, capital availability and cost, prevailing conditions in energy and input markets and capacity constraints in the drilling industry. The allocation of this effort amongst various

geological propects depends upon the recent results in that particular play relative to the results in the province as a whole. Several characteristics of such an approach are immediately apparent. For instance, a change in petroleum tax regulations, or drilling costs, would affect general operating conditions, and therefore overall industry activity, but without any significant effect upon the proportion of activity allocated to any one play--royalty increases, for example, would mean reduced drilling in all plays. On the other hand, a number of unusually large discoveries in one oil play could have two effects: first, by raising the average discovery size in the province as a whole, it could induce a rise in total exploratory effort; second, the rise in the average discovery size in this play relative to other plays could induce a greater proportion of wells to penetrate this horizon.

Obviously the present study does not present a fully worked and empirically verified version of this approach, but it does suggest that it is a useful way to view aggregate industry activity in Alberta.

4.4 Oil Discovered and Enhanced Recovery in Alberta

The analysis of Chapter 3 focussed upon the exploration process and the discovery of oil-in-place and primary recoverable reserves. Additional reserves may be recoverable by enhanced recovery (E.R.) techniques, if the operators expect such schemes to be profitable. It is not clear, however, to what extent companies may have an expectation of enhanced recovery reserves at the time of exploration. It seems unlikely that firms have had any very pronounced expectation in this direction, since the attractiveness of E.R. techniques seems to depend heavily upon specific reservoir characteristics (which can not be known until after discovery), and since there appear to have been more significant technological advances in E.R. techniques than in primary techniques in the past three decades. Moreover, as Appendix B shows, of the seven oil plays examined here, in only the Beaverhill Lake play have more than one in five pools installed E.R. schemes. Hence such schemes can hardly have been anticipated on average. (In the Beaverhill Lake play 14 of the 20 pools have such schemes, so it may be an exception.) Finally, in most of the pools examined here, the E.R. schemes were begun several years after discovery, which suggests that they were introduced in response to technological changes and/or economic-regulatory conditions other than those associated with the initial discovery. This study does not incorporate any extensive analysis of E.R. reserves.

One might, however, ask whether the enhanced recovery reserves exhibit the same technological relationship as that examined in Chapter 3 for both oil-in-place and primary recoverable reserves. Accordingly, the enhanced recoverable reserves data was arranged by year of discovery of the oil pool, and the volumes related to discovery effort (as measured by penetrations to the formation) and cumulative penetrations (to measure a depletion effect). Discovery year information (rather than the starting year of the E.R. schemes) was used, since the purpose was to see if discovery of the oil subsequently recoverable by E.R. means followed the same pattern as did the primary reserves. No significant regression equations of the sort derived in Chapter 3 were found for E.R. volumes. Moreover, if primary and enhanced reserves were combined, and the technological discovery relationship of Chapter 3 rerun on total recoverable volumes, most of the oil plays did not show a significant relationship, even for the four plays for which a significant relationship was found for primary recoverable reserves (i.e., the Leduc, Keg River, Beaverhill Lake and Nisku formations, as shown in Table 3.1).

Thus, there is strong support for the proposition that primary and enhanced recovery reserves are 'found' in quite different ways. Moreover, if the hypothesis of Chapter 3 is accepted as reasonable (that large reserves of oil tend to be found first), the implication is that the exploratory process tends to be governed mainly by considerations of oil-in-place or primary recoverable reserves. Expectations about enhanced recovery volumes must come largely after discovery of the pool.

Footnotes

[1]The actual estimated equation with related statistics (using the symbols of Table 3.1) was:

$$\ln(\text{Discoveries}_t) = \underset{(0.44)}{4.32} + \underset{(0.57)}{1.02}\ \ln(\text{Penetrations}_t) - \underset{(0.13)}{0.000029}\ (\text{Cumulative Penetrations}_{t-1})$$

$R^2 = 0.05$
D.W. = 1.96

[2]See Uhler (1979) and Epple (1975). A. Wright and J. Cox have published a number of articles, including "The Cost Effectiveness of Federal Tax Subsidies for Petroleum Reserves" in G. Brannon (ed.), Studies in Energy Tax Policy, (Cambridge: Ballinger, 1974), and J. Cox and A. Wright, "The Determinants of Investment in Petroleum Reserves and Their Implications for Public Policy," American Economic Review, Vol. LXVI (1976). See also Eckbo, Jacoby and Smith (1978).

[3]It can be appreciated that the underlying assumptions form a major part of such models. It is common, for example, to assume that firms act to maximize the present value of profits and that they react to a particular set of price, cost and tax regulations. This could be taken to mean that all firms are identical, but is usually interpreted as the representation of some 'average' firm; specific companies may have quite different expectations or behavioural motivation, but if all firms are considered together such differences are randomly distributed around the average. If this view of the individual firm is supplemented by assumptions that the industry is perfectly competitive, that industry activity is unconstrained by short-run supply limitations and that a particular form of the production function (e.g., Cobb Douglas, trans-log, constant elasticity of substitution, etc.) gives input-output possibilities, then specific empirically testable relationship can be derived. Obviously many different models of this sort can be constructed, and economists tend to select one on 'instrumental' grounds (if it works, it is satisfactory) with a presumption that the simpler it is, the better.

[4]In addition to the sources of footnote 2, there have been a number of oil supply studies in the U.S.A. The three pathbreaking early studies are: F. Fisher (1964); Erickson and Spann (1971); MacAvoy and Pindyck (1975). Evaluative reviews of a number of major oil supply studies can be found in P. Clark, P. Coene and D. Logan, "A Comparison of Ten U.S. Oil and Gas Supply Models," Resources and Energy 3 (1981), pp. 97-335; and D. Epple, "Studies of U.S. Primary Energy Supply: A Review," Energy Systems and Policy 2 (1978), pp. 245-265.

[5]Oilweek "Annual Review and Forecast," February 11, 1980, p. 56.

[6]It might also be suggested that the strict linear equation is unduly restrictive, and that 'logistic' equations bounded by values of 0 and 1 might be more realistic. Estimation equations of this form have not been tried in this preliminary work.

Chapter 5

SUMMARY

Oil exploration decisions may be viewed from many perspectives. The individual company in the petroleum industry will focus upon specific potential drilling sites and decide whether or not to drill in light of the company's current tax and financial positions and its geological, economic and regulatory expectations. Frequently, however, a perspective much broader than the individual well location is required. Policy analysts in and outside the government have more interest in the aggregate of industry activity than in a particular company's success at a single drilling site; companies can assess the desirability of individual locations only in light of their expectations about market developments as a whole. Therefore, even though we might argue that the only thing which ultimately matters is the success of individual wells, the modelling of aggregate industry activity is an issue of major importance. As is frequently the case this involves the search for proper balance between two extremes: on the one hand, a model is desired which is a realistic depiction of the independent actions of a large number of separate decision makers in a complex physical world; on the other hand, it is useful to have a model which is highly aggregated, relatively simple and relies upon information in the public domain. This study has been concerned with the development of an aggregate model of oil exploration in Alberta which preserves important geological differentiation; in particular, the study focuses upon the concept of an oil 'play'.

At the end of 1976, 65 percent of the discovered Alberta oil-in-place, and 78 percent of the estimated discovered recoverable oil, came in five oil plays: the Cardium sandstone formation in the Upper Cretaceous, and the Nisku (D-2), Leduc (D-3), Beaverhill Lake and Keg River formations of Devonian age. The Viking (Lower Cretaceous) and Granite Wash (Middle Devonian) accounted for another 11.6 percent of estimated recoverable reserves. Thus, a relatively small number of geologic formations accounted for most Alberta oil. Furthermore, perusal of historical reports in oil journals makes clear that each of these major oil plays operated as a powerful magnet to exploratory drilling, after the initial discovery. Since each discovery depletes the stock of undiscovered pools by one, it is physically inevitable that oil plays will eventually run down. Analysis of the distribution of the physical characteristics of pools within each of the main plays

indicated that pool area, estimated oil-in-place and estimated recoverable oil reserves (using appreciated reserves) all fit a log-normal distribution, with a relatively small number of large pools and much larger number of small pools. To the extent that companies are able to differentiate between pools (or if drilling were random, and success related to pool area) one would expect a particular sequence of discoveries within each play: the larger pools would tend to be discovered earlier. Other studies had found that this relationship held for distinct geographic areas: the major part of this study was designed to see if the relationship held for the geological unit (oil plays) as well. The specific relationship tested was a log-linear one which allowed for more oil to be found the greater the number of exploratory wells drilled in a year, but which specified a negative exponential relationship between new discoveries and the total of industry activity up to that time. In other words, it was hypothesized that oil exploration within a specific play would become increasingly less productive as time passed due to depletion of the remaining undiscovered oil supply.

In order to test this relationship, geographic areas of the province were defined to encompass each of nine oil plays (the seven noted above, plus Slave Point and Sulphur Point). In each of these areas we counted the number of exploratory wells (other than outpost wells) which penetrated the relevant geologic horizon each year. In several cases it was felt advisable to adjust the penetration data slightly to reflect the fact that two geological zones of great interest lay within that area, or that the zone became very important for natural gas in the late 1960s. Then, for each of the nine geological plays, least-squares regression equations were fitted to annual data from the year of the initial discovery in the play up to 1976; in these equations the volume of oil found was the dependent variable (either oil-in-place or primary recoverable reserves) while annual penetrations and the cumulative number of penetrations up to the previous year were independent variables. It was expected that the first of these independent variables could be positively related to new volumes discovered and the latter negatively.

This relationship, with the expected signs, proved to be statistically significant at the 5 percent level for four Alberta oil plays: Leduc, Nisku, Beaverhill Lake and Keg River. For the Cardium play, the variables had the anticipated signs, but the overall significance level was less, particularly if allowance was made for further appreciation of more recent finds. Thus, for four of the major oil plays in Alberta a common pattern of development was indicated.

Projection of these equations to show the results from hypothesized penetrations to the four main formations in the years 1977 through 1980 indicated that only in the Keg River formation were significant volumes of oil likely to be found. A major factor underlying the declining effectiveness of exploratory effort over time was the decline in the average size of a discovery. For all four plays this negative relationship was statistically significant at the 5 percent level. This result may also reflect the lack of reserves appreciation in more recent discoveries, although it was argued that this effect is likely to be small.

However, for the Cardium, Viking, Granite Wash, Slave Point and Sulphur Point oil plays, no statistically significant relationships were found. Three underlying reasons for this were suggested. First, a play-oriented approach necessarily involves joint-product problems, especially for shallower geologic horizons. (In the absence of information on the intent of the company drilling the well, it is not possible to determine whether each and every penetration of a geological zone reflects a real interest.) Therefore, the number of penetrations through a specific formation, particularly a shallow one, may be biased. In the present case such bias is most likely in the Viking and Cardium formations. Second, it seems very likely that some oil-bearing geologic formations are believed to contain so little oil that no pronounced oil play develops. Third, in some formations there may be little ability to distinguish prospective drilling sites or prospects expected to be of larger size. In this case discoveries of approximately average size may continue as long as there is any unexplored area remaining in the formation. Continuing discoveries, after 1976, in the Cardium and Viking formations suggest that this may be true here.

The finding that a significant negative exponential discovery relationship exists for the major Alberta oil plays is of potential value to those engaged in aggregate modelling of the Canadian petroleum industry: it says something about the likelihood of further discoveries in four of the five main historical Canadian oil plays, and it tells us something about the likely pattern of development of new oil plays.

But a full picture of the supply of oil from a region can not be obtained from the discovery sequence within a major oil play. A number of the other pieces of the puzzle were addressed in this study, although in a more preliminary manner. The major conclusions derived can be summarized as follows.

No significant regression equations of the negative exponential type could be found for Alberta oil discoveries up to 1976, outside the four major plays. As noted above, no relationship was found for the Cardium, Viking, Granite Wash, Sulphur Point and Slave Point plays; nor was a relationship found for a 'residual' category including oil found outside the nine plays studied here. This might be taken to suggest that aggregate annual oil finds outside the major plays can best be estimated by some type of random drilling model, or that separate plays cannot be successfully aggregated prior to estimating a supply relationship. This is not, of course, the same as saying that each individual company might as well select its particular drilling sites at random. Geological information does, after all, grow over time.

No significant regression equations of the negative exponential type were found for 'discoveries' of enhanced recovery reserves (defined to include secondary recovery). This suggests that it is the oil-in-place or primary recoverable reserves which are the focus of the exploration decision. As might be expected, the addition of recoverable reserves from secondary or tertiary recovery schemes is the focus of decision making only after discovery and initial development, but such decisions were not subject to analysis in this study.

The major oil plays within Alberta do not seem to follow a negative exponential relationship themselves, with smaller plays discovered later. Simple observation does suggest that the lag between plays increases with the total number of plays and that more distant plays--geographically and geologically--tend to be found later.

Finally, least squares estimation showed that the relative exploratory effort going to any one of the major oil plays was positively related to the size of the average oil discovery in that play relative to the province as a whole. Such a play-orientated approach could form a useful part of an oil exploration model. However, an attempt to estimate a simple aggregate equation to explain the total number of exploratory wells drilled within Alberta did not yield satisfactory results. In particular, it was expected that the level of exploratory drilling would be positively related to the real price of oil, net of royalties; but the oil price variable was significant only with a negative sign. This suggests the need to consider more complex models of the exploration decision, possibly including geological factors, a more elaborate model of price expectations, formal recognition of drilling costs and a model of drilling rig capacity. Much room remains for fruitful aggregate modelling of the Alberta oil industry.

APPENDIX A

REVIEW OF TAX TREATMENT ON ALBERTA PETROLEUM 1947-1978

No significant regression equations of the negative exponential type could be found for Alberta oil discoveries up to 1976, outside the four major plays. As noted above, no relationship was found for the Cardium, Viking, Granite Wash, Sulphur Point and Slave Point plays; nor was a relationship found for a 'residual' category including oil found outside the nine plays studied here. This might be taken to suggest that aggregate annual oil finds outside the major plays can best be estimated by some type of random drilling model, or that separate plays cannot be successfully aggregated prior to estimating a supply relationship. This is not, of course, the same as saying that each individual company might as well select its particular drilling sites at random. Geological information does, after all, grow over time.

No significant regression equations of the negative exponential type were found for 'discoveries' of enhanced recovery reserves (defined to include secondary recovery). This suggests that it is the oil-in-place or primary recoverable reserves which are the focus of the exploration decision. As might be expected, the addition of recoverable reserves from secondary or tertiary recovery schemes is the focus of decision making only after discovery and initial development, but such decisions were not subject to analysis in this study.

The major oil plays within Alberta do not seem to follow a negative exponential relationship themselves, with smaller plays discovered later. Simple observation does suggest that the lag between plays increases with the total number of plays and that more distant plays--geographically and geologically--tend to be found later.

Finally, least squares estimation showed that the relative exploratory effort going to any one of the major oil plays was positively related to the size of the average oil discovery in that play relative to the province as a whole. Such a play-orientated approach could form a useful part of an oil exploration model. However, an attempt to estimate a simple aggregate equation to explain the total number of exploratory wells drilled within Alberta did not yield satisfactory results. In particular, it was expected that the level of exploratory drilling would be positively related to the real price of oil, net of royalties; but the oil price variable was significant only with a negative sign. This suggests the need to consider more complex models of the exploration decision, possibly including geological factors, a more elaborate model of price expectations, formal recognition of drilling costs and a model of drilling rig capacity. Much room remains for fruitful aggregate modelling of the Alberta oil industry.

APPENDIX A

REVIEW OF TAX TREATMENT ON ALBERTA PETROLEUM 1947-1978

Appendix A

REVIEW OF TAX TREATMENT ON ALBERTA PETROLEUM 1947-1978[1]

A.1 Royalties

Most petroleum production is from provincial Crown land, and is assessed a gross ad valorum royalty (i.e., a royalty based on the selling price of the product). The effective royalty rates are summarized below, for individual producing wells (x is output).

1947 - May 7, 1949

Crude Oil - 10%
Natural Gas - 15%

May 8, 1949 - April 30, 1951

Crude Oil - 12 1/2%
Natural Gas - 15%

June 1, 1951 - March 31, 1962

Crude Oil -

(barrels/month) of production	(barrels/month) royalty
0-600	5% of output
600-750	30 + 0.14 (x-600)
750-950	51 + 0.17 (x-750)
950-1150	85 + 0.18 (x-950)
1150-1500	121 + 0.19 (x-1150)
1500-1800	12-1/2% of output
1800-4050	225 + 0.20 (x-1800)
over 4050	16-2/3% of output

Natural Gas - 15% of selling price (or fair market value), minimum 3/4¢/Mcf.

April 1, 1962 - December 31, 1972

Crude Oil -

(barrels/month) of production	(barrels/month) royalty
0-750	8% of output
750-2700	60 + 0.20 (x-750)
over 2700	16-2/3% of production

Natural Gas - 16-2/3% of fair value (selling price less processing costs)

January 1, 1973 - April 1, 1974

Crude Oil -

(barrels/month) of production	(barrels/month) royalty
0-1200	$\frac{x}{120} + 0.50 \frac{x}{(100)}$
over 1200	180 + 0.25 (x-1200)

April 1, 1974

Crude Oil -

Royalty = $S + \frac{kS\ (A-B)}{A}$ where S is the January 1973 royalty, A the 'par price', B the 'select price' and k the royalty factor. Values have been set as follows:

	A	B	k 'old' oil	k 'new' oil
April 1974	6.81	4.11	1.9390	0.5600
Jan. 1975	6.81	4.71	1.9390	0.5600
July 1975	8.31	4.71	1.7350	0.6140
July 1976	9.36	4.71	1.6096	0.5960
Jan. 1977	10.06	4.71	1.5985	0.6154
July 1977	11.06	4.71	1.5701	0.6262
Jan. 1978	12.06	4.71	1.5452	0.6311
July 1978	13.06	4.71	1.5178	0.6303

'New oil' is that from (1) new pools discovered after April 1, 1974, (2) new wells in older pools but producing from areas outside the designated pool boundary as of April 1, 1974, and (3) enhanced recovery schemes effective after April 1, 1974.

Natural Gas - (effective January 1, 1974)
(The symbol P represents the actual sales price)

Gas Selling Price (¢/Mcf)	Percentage Royalty	
	'Old Gas'	'New Gas'
0-26	22	22
26-28	[572 + 25 (P-26)] ÷ P	[572 + 24 (P-26)] ÷ P
28-30	[620 + 30 (P-28)] ÷ P	[620 + 26 (P-28)] ÷ P
30-32	[682 + 35 (P-30)] ÷ P	[672 + 28 (P-30)] ÷ P
32-34	[752 + 40 (P-32)] ÷ P	[728 + 30 (P-32)] ÷ P
34-36	[832 + 45 (P-34)] ÷ P	[788 + 33 (P-34)] ÷ P
over 36	[922 + 50 (P-36)] ÷ P	[854 + 35 (P-36)] ÷ P
maximum	50	35

A.2 Corporate Income Tax Provisions

Since 1961 the corporate income tax has been a shared federal-provincial tax, with much the same regulations for both Ottawa's and Alberta's portion. Prior to 1952 there was an Alberta provincial income tax on petroleum. From 1953 through 1961 there was no provincial tax since Ottawa 'rented' the provincial tax authority. The government of Alberta has declared its intention of leaving the shared-tax agreement in 1982 to impose its own corporate income tax. Tax regulations have varied somewhat between companies whose 'principal business' is in the petroleum industry, and others. This summary relates to the petroleum companies.[2] Table A.1 summarizes the corporate income tax rates in years since 1947, and the comments below describe the most important changes in tax regulations.

1947, 1948

(a) Development costs were capitalized over 5 years, 30 percent the first year falling to 10 percent the final year.

(b) A depletion allowance of 33-1/3 percent of the net profit from oil wells (25 percent from gas wells). Net profit was revenues less operating costs less allowable development expenditures.

TABLE A.1

CORPORATE INCOME TAX RATES
(percent)

Year	Federal[a]	Provincial
1947	30.00	5
1948-51	33.00	5
1952	52.00	0
1953-54	49.00	0
1955-57	47.00	0
1959-61	50.00	0
1962-66	41.00	9
1967	40.00	10
1968-70	41.41	11
1970-71	36.71	11
1972	36.50	11
1973	39.00	11
1974	40.60	11
1975	38.20	11
1976-79	36.00	11
1980	37.80	11

SOURCE: Canadian Tax Foundation, The National Finances.

[a]Excludes abatements applied to Alberta; includes federal Old-Age Security Tax. The rate given is that on all taxable income in excess of a small initial amount assessed at a lower rate. Also included are several temporary schemes. For example:

(1) May 1966-March 1967, a 5 percent refundable tax on 'cash profit'

(2) Temporary 3 percent tax cut July 1, 1971 to December 31, 1971

(3) Reduced rate since 1973 on manufacturing and processing income (a federal tax rate 9 percentage points lower)

(4) The federal tax rate on mineral industries was reduced to 30.6 percent in 1974 and 26.2 percent in 1975, after royalties paid to the provinces were made nondeductible.

1949 (major changes occurred under the 1948 Income Tax Act)

(a) One hundred percent of exploration expenditures and pre-production drilling expenditures could be deducted in the year incurred.

(b) Bonus payments and lease costs in excess of $1/acre/year were not deductible unless the land was unproductive and surrendered.

(c) Other capital costs of development could be capitalized over time, generally on the same basis as prior to 1949.

(d) Companies could claim a depletion allowance of 33-1/3 percent of net income from crude petroleum activities. (Effective in 1951 this depletion allowance was applied to the aggregate of all wells the company owned; hence, the allowance was of immediate use only to those companies in an aggregate taxable position.)

(e) From 1949 through 1957 a 30-35 percent tax credit was available on the cost of unproductive deep tests, if the government allowed.

1962

Land acquisition costs, including bonus payments, made after April 10, 1962 are deductible as an exploratory expense (i.e., 100 percent deductible in the year incurred.)

1974

(a) The depletion allowance replaced with 'earned depletion'; $1 for every $3 of exploration and development expenditure to a maximum of 25 percent of net production profit.

(b) Royalties to provincial governments were not deductible as a cost in calculating the federal portion of the tax.

(c) Companies could obtain a credit of up to $1 million on income tax, rental and royalty payments to the province of Alberta.

(d) Extra abatement on resource profits of 10 percentage points of the federal tax in 1974, and 12 percent in 1975. (In 1976 this was replaced with an additional deduction, the 'resource allowance', equal to 25 percent of adjusted production revenue, i.e., revenue less operating costs and capital cost allowances.)

(e) Capital consumption allowance on intangible development expenditures changed from immediate write-off to 30 percent on a declining-balance basis.

A.3 Land Provisions

The government of Alberta has had a variety of mineral right classifications since 1947. The broadest division is between rights which allow exploratory drilling but not production (reservations, permits and licenses) and those which allow production (leases). The exploratory rights are convertible in whole or in part into leases. Not all the provisions of the many specific forms of mineral rights will be reviewed here, but several common features will be summarized.

(1) Bonus Bids

Most mineral rights are issued to the highest bidder in a sealed-bid auction. (Some early rights were not auctioned, and leases obtained by conversion of exploratory rights are not subject to bidding, although the exploratory rights usually were.) Companies may request that certain areas be put up for bid. The government has the right to refuse bids which it feels are insufficient.

(2) Rental Payments

The most common rental payment, that applied on leases, has been $1/acre. Rental payments per acre on exploratory rights are often set at a lower rate in the initial year, then rise; exploratory expenditures can frequently be credited against rental payments owing on such rights.

(3) Work Requirements

Often mineral rights lapse unless exploratory activity is undertaken, or a higher rental paid. The government may order that exploration occur.

(4) Term

Leases can be held while production occurs. Non-productive leases may be held idle until the government orders exploratory activity. (Since 1976, such activity must occur within 5 years, and may be ordered earlier.) Exploratory rights have usually had a term of 5 years or less.

A.4 Exploratory Incentive Schemes

Starting in 1972 the government of Alberta introduced incentives to encourage further exploration in the province.

(1) Exploratory Drilling Incentive Plan

August 1, 1972 to December 31, 1973:

(a) A 5-year royalty holiday on oil from a successful new field wildcat well in a previously unproductive structure. (A reviewer has noted that this programme was in effect at the time of the West Pembina discovery.)

(b) A provincial tax credit (applied against royalties) based on the total footage of new field wildcats; this averaged about 30 percent of the cost of the well.

January 1, 1974 to December 31, 1974:

(a) A 2-year royalty holiday on a new field natural gas success.

(b) Different credit amounts for different areas of the province (plains, foothills and north).

(c) Credits applicable against bonuses.

(d) Deeper footage of deeper pool exploratory tests became eligible.

January 1, 1975 to December 31, 1977:

(a) Credits larger for deeper wells.

(The program was extended on January 1, 1978 including larger credits for deeper footage.)

(2) Geophysical Incentives Plan

January 1, 1975 to December 31, 1978:

(a) Incentives for three areas, green, foothills and plains

(b) Credit required a minimum standard of subsurface coverage

(c) The results from surveys which received credits would be made available to others, at a cost, 3 years after the survey.

(This program was continued, with a reduced credit, in 1979.)

A.5 Effect of Tax Regulations on Oil Profits

A.5.1 Introduction

If it is assumed that companies act to maximize profits (the net present value of the venture) then taxes will be viewed as a cost of production and an incentive credit as a revenue flow. Clearly changes in tax regulations will affect the expected profitability of projects, and hence change the level and nature of industry activity. The precise effect is very difficult to estimate, for reasons given in the main text of this paper. (There is inevitably great uncertainty about the geological and technical parameters in the industry, as well as the future level of key economic variables; not all companies will see these factors in the same way; the impact of a particular tax on a particular project may vary from company to company depending upon the tax position of the company.)

This section of Appendix A will present a simple representation of the net present value of a project (assuming that all revenues and cost flows are known with certainty). It will show the general effect of the various major taxes on petroleum production in Alberta. Following this, we will consider the nature of the major changes in regulations over this period. This study is concerned with exploratory activity, so that all crude petroleum costs must be considered variable. It will be assumed that companies are large enough, and in an overall taxable position, so that they can take full advantage of provisions to minimize their total tax burden. (That is, allowable capital consumption allowances and depletion allowances need not be carried forward due to insufficient current income.) This will understate the tax burden on some companies, especially in the earlier years of their activity.

A.5.2 Effect of Taxes on a Project

The following symbols are used:

NPV	Net Present Value
i	the marginal opportunity cost of investment (discount rate)
P_t	Price of oil in year t
q_t	Quantity of oil produced in year t (abstract from joint products)
r_t	Gross royalty rate in year t
C_t	Operating costs in year t (including annual land rentals)

B_t Bonus bid expenditures in year t

I_t Incentive payments (on exploration)

G_t Geological and geophysical expenditures in year t

E_t Exploratory drilling expenditures in year t

D_t^1 Intangible drilling expenditures in year t

D_t^2 Enhanced recovery expenditures in year t

D_t^3 Other development expenditures in year t

R_t Royalties in year t

RA_t Resource allowance in year t

DA_t Depletion allowance in year t

t_f Federal corporate income tax rate

t_p Provincial corporate income tax rate

d Net depletion allowance rate

e_i Exploratory incentive credit rate (i is either o , for geological, or 1, for drilling).

a Resource allowance rate

c^i Annual Capital consumption allowance rate, on a declining balance method. (The superscript refers to the equipment class considered; o for bonus bids, 1 for geological, 2 for exploratory drilling, 3 for intangible development, 4 for enhanced recovery, and 5 for other development. It is assumed that all the investment falls in one of these categories; if expenditures may be expensed immediately the variable c^i is not required. CCA_t^i is the capital consumption allowance on group i in year t .)

Assume that the project under consideration has a lifetime of T + 1 years from the current year (0) to the final year (T). The formula below uses discrete discounting and may be interpreted as giving the NPV of the project as seen from the middle of the initial year. All values are expressed in current dollars (so the rate of discount must be viewed as a nominal rate).

The profit (NPV) of a project is the present value (discounted value) of all revenues and incentive payments less the present value of exploration costs, development costs, operating costs and taxes (royalties and corporate income taxes).[3] The major components in NPV may then be represented as follows:

(1) Revenue

$$\sum_{t=0}^{T} p_t q_t (1 + i)^{-t}$$

(2) Incentives

$$\sum_{t=0}^{T} I_t (1 + i)^{-t} = \sum_{t=0}^{T} e_o G_t (1 + i)^{-t} + \sum_{t=0}^{T} e_1 E_t (1 + i)^{-t}$$

(3) Costs

$$\sum_{t=0}^{T} C_t (1 + i)^{-t} + \sum_{t=0}^{T} B_t (1 + i)^{-t} + \sum_{t=0}^{T} G_t (1 + i)^{-t} + \sum_{t=0}^{T} E_t (1 + i)^{-t}$$

$$+ \sum_{t=0}^{T} D_t^1 (1 + i)^{-t} + \sum_{t=0}^{T} D_t^2 (1 + i)^{-t} + \sum_{t=0}^{T} D_t^3 (1 + i)^{-t}$$

(4) Royalties

$$\sum_{t=0}^{T} p_t q_t r_t (1 + i)^{-t}$$

(5) Federal Income Taxes
(x is zero if royalties are not deductible; otherwise it is one)

$$\sum_{t=0}^{T} \{t_f (p_t q_t - C_t - xR_t - RA_t - DA_t - \sum_{i=1}^{5} CCA_t^i)(1 + i)^{-t}\}$$

(6) Provincial Income Taxes
(royalties are deductible and there is no resource allowance)

$$\sum_{t=0}^{T} (t_p(p_t q_t - C_t - R_t - DA_t - \sum_{i=1}^{5} CCA_t^i)(1 + i)^{-t})$$

Several simplifying assumptions have been made in this presentation. For example, incentive payments are assumed to be nontaxable. Also there is no allowance for the fact that the tax regulations might induce the operator to change his production plan: if royalty rates are a function of the level of output, changes in the rate structure may influence the output level; if the depreciation schedule for a particular type of capital equipment changes, the company may elect to use more or less of it and less or more of other inputs.[4]

It is also evident that several of the components of the tax equation must be examined in more detail (specifically the resource allowance, RA, depletion allowance, DA, and capital consumption allowance, CCA_t^i).

(1) Resource Allowance

This is an additional deduction from income, introduced in 1975, essentially to make up for the nondeductibility of royalties in the federal income tax. Obviously such an allowance can be defined in a number of ways. Currently (with a = 25%):

$$RA_t = (a)\ (p_t q_t - C_t - CCA_t^4 - CCA_t^5)$$

(2) Depletion Allowance

There have been two 'types' of depletion allowance in Canada. Prior to 1974 the depletion allowance was calculated as (with d = 0.333):

$$DA_t = (d)\ (p_t q_t - C_t - R_t - \sum_{i=1}^{5} CCA_t^i)$$

Since 1974, the basic allowance has been:

$$DA_t = 1/3(G_t + E_t + D_t^1)$$

This is subject to net income limitation as well. That is:

$$DA_t \leq (.25)\ (p_t q_t - C_t - R_t - \sum_{i-1}^{5} CCA_t^i)$$

(3) Capital Consumption Allowances

In general, capital consumption allowances have been calculated on a declining balance method, with a proportion (c) of the remaining balance claimed each year. In such an instance, the CCA in the year 't' after the investment (I) will be

$$CCA_t = c(1-c)^t I$$

and the undepreciated sum remaining is $(1-c)^{t+1} I$. (The capital consumption allowance in the initial year, with t = 0, is cI.) The present value of the capital consumption allowance is less than the cost of the investment, unless the expenditure may be deducted immediately in the year incurred (i.e., unless c = 1). The present value of the capital consumption allowance (at rate of discount i) is given by:

$$I(\frac{c + ci}{c + i})$$

If a project commenced in year 0 and I was investment in year τ, the capital consumption allowance in year t for class of equipment i (CCA_t^i) would be given by:

$$CCA_t^i = \sum_{\tau=0}^{t} c(1-c)^{(t-\tau)} I_\tau$$

It is evident that the formulation for Net Present Value becomes very complex when all the terms and regulations are included. Profit depends upon the following variables:

(1) Output Levels (q_t)

These, in turn, are dictated in large part by reservoir conditions, the investment in the pool, and government regulation

(especially such conservation regulations as those of market demand prorationing). Beyond this, of course, the operator always has the option of producing at less than allowable capacity.

(2) Oil Prices (P_t)

(3) Input Expenditures (C^t, G^t, E^t, D_t^1, D_t^2 and D_t^3)

These depend upon the precise form of action taken by the operator (the mix of inputs chosen and the prices of the inputs). While technological factors are an important determinant of this action, the operator has the ability to vary the overall level of activity and to substitute some inputs for others.

(4) Tax regulations (r_t, t_f, t_p, d, e_j, a, c_j, etc.)

The complexity of the profit calculation can be further reduced by a number of simplifying assumptions about these variables. For example, assume that geological expenditures on particular properties have been undertaken (so are fixed expenditures) and assume that enhanced recovery decisions must be taken later in the life of the reservoir and are not anticipated.

(Therefore, $G_t = o$ and $D_t^2 = o$.)

Assume that exploratory drilling expenditures are undertaken only in the initial year of the project.

(Therefore $E_t = o$ except for E_o.)

Assume that development expenditures also occur in a single year n years after exploratory.

(Therefore, $D_t^1 = o$ and $D_t^2 = o$ except for D_n^1 and D_n^2 .)

Further, through most of the period under study, both exploration expenditures and intangible drilling costs were entirely deductible for income tax purposes in the year in which they were incurred (i.e., c_2 and $c_3 = 1$). Only after 1974 were intangible drilling expenditures depreciated overtime ($c_3 = 0.3$). Finally, continue to assume that the operator is able to take advantage of the tax provisions at the most favourable time; he need not carry any forward to later dates.

Under these conditions the Net Present Value could be written as follows:

$$NPV = \sum_{t=0}^{T}(1-r_t)p_t q_t\,(1+i)^{-t} - \sum_{t=0}^{T}((1-a)t_f + t_p)p_t q_t\,(1+i)^{-t}$$

$$+ \sum_{t=0}^{T}(t_f x + t_p)(r_t p_t q_t)(1+i)^{-t} - \sum_{t=0}^{T}(1 - (1+a)t_f - t_p)C_t(1+i)^{-t}$$

$$- (1-t_f-t_p)E_o - (1-t_f-t_p)D_n^1(1+i)^{-n}$$

$$- \sum_{t=n}^{\infty}(1-(t_f+at_f+t_p)c_5(1-c_5)^t)D_n^3\,(1+i)^{-t} + \sum_{t=0}^{T}(t_f+t_p)(DA_t)(1+i)^{-t}$$

$$+ \sum_{t=0}^{T} I_t(1+i)^{-t}$$

(It will be recalled that the depletion allowance provisions took two quite different forms over the period 1947-1976). This expression for profit is already somewhat simplified, but does capture the most important characteristics of the exploratory investment decision in Canada. At the same time, we must remember that such profit calculations are undertaken by individual decision-makers, and rely upon expectations of future price, cost and regulatory conditions. Accordingly, if one is examining industry activity in the aggregate, the profit formulation must be viewed as the 'average' expectation of the 'average' firm. From that starting point, assumptions to simplify the NPV formula become increasingly arbitrary.

Among assumptions often made are the following.

(a) The expected values of future price, cost and tax levels are those currently observed, or some constant level calculated from values in the recent past. Thus, for

example, many models place great emphasis upon the actual 'netback' price (price less royalty) in the year the exploratory decision is undertaken. These netback prices of oil and gas are shown in Table A.2. (Clearly this reflects the net receipt per unit in the field, i.e., after production, which differs from the value of a unit in the ground; the latter reflects the discounted revenue per unit over the life of the reservoir. Nor does this unit price make any allowance for the actual cost of production and the impact of corporate income taxes.)[5]

(b) The net present value depends upon how the oil is produced over time, that is the time path of production. One could calculate the per barrel NPV of a barrel of oil in the ground; this would be the NPV divided by the number of barrels of proved reserves. Given the anticipated prices, costs and taxes (e.g., the current values, as just discussed) then the NPV depends upon how the reserves are allocated over time.

A common assumption in economic analyses is that the output follows a path of exponential decline. (This is viewed as a reasonable approximation to the more general path of hyperbolic decline which is apparently common to most oil pools, for any given intensity of development.) In exponential decline, the entire production path can be defined by the initial output rate (q_0) and the constant annual percentage output decline (d). That is,

$$q_t = q_0 e^{-dt}$$

If we combine the assumption of constant exponential decline with the assumption that all future prices, costs and taxes take on the current year (year '0') value, and assume that the operating costs of the pool in total are the same in all years, then the NPV can be considerably simplified. If discounting is expressed in the continuous fashion:

$$NPV = (1-r_o)p_o q_o \int_o^T e^{-(d+i)t}dt - \{(1-a)t_f+t_p\}p_o q_o \int_o^T e^{-(d+i)t}dt$$

$$+ (t_f x+t_p)r_o p_o q_o \int_o^T e^{-(d+i)t}dt - \{1-(1+a)t_f-t_p\}C_o \int_o^T e^{-(d+i)t}dt$$

$$- (1-t_f-t_p)\{E_o+D_n^1(1+i)^{-n}\} - D_n^3(1+i)^{-n}$$

$$+ (t_f-at_f+t_p)c_5 D^3 \int_n^\infty (1-c_5)^t e^{-it}dt$$

$$+ \int_o^T (t_f+t_p)DA_t e^{-it}dt + \int_o^T I_t e^{-it}dt$$

Given revenues and costs this can be solved if values are available for: r_o, a, t_f, t_p, c_4, and DA_t (i.e., the tax regulations), d (the decline rate of the pool), i (the discount rate), n (the time of installation of development equipment) and T (the date of abandonment of the pool).

The assumption of continuous exponential decline is extreme. Most pools can maintain constant production for several years before decline commences. Moreover, there is no allowance for infill drilling or subsequent enhanced recovery operations. Nor is any recognition given to the Alberta market demand prorationing schemes (which have held output of many pools below capability, and also, at least until the 1964 revision, induced larger than necessary expenditures on development and lifting).[6]

Columns 3 and 4 of Table A.2 include rough estimates of the real per barrel anticipated value of a newly discovered barrel of oil, for each year from 1949 through 1976. These estimates are derived from Equation A.1 and a number of assumptions designed to derive values for the various quantities and tax variables in that equation. Amongst the major assumptions are the following.

TABLE A.2

UNIT VALUES OF ALBERTA CRUDE OIL AND NATURAL GAS[a]

Year	Real Netback Price (1971 dollars)		Value of Oil in the Ground (1971 dollars)	
	Oil ($/bbl)	Natural Gas (¢/Mcf)	Case 1 ($/bbl)	Case 2 ($/bbl)
1947	5.14	12.7	n/a	n/a
1948	5.45	10.7	n/a	n/a
1949	4.52	10.3	1.87	0.70
1950	4.54	9.1	1.75	0.63
1951	3.48	8.5	1.44	0.81
1952	3.09	12.6	0.82	0.55
1953	3.25	12.3	0.88	0.62
1954	3.39	12.1	0.92	0.71
1955	3.18	12.2	0.87	0.35
1956	3.07	12.2	0.85	0.10
1957	3.21	12.6	0.90	0.30
1958	3.08	13.2	0.80	0.26
1959	2.87	11.5	0.72	0.17
1960	2.80	11.5	0.70	0.22
1961	2.82	14.2	0.64	(0.57)
1962	2.93	14.4	0.64	(0.12)
1963	2.91	15.5	0.70	0.18
1964	2.85	15.9	0.70	0.16
1965	2.76	15.2	0.68	0.18
1966	2.64	15.1	0.66	0.17
1967	2.54	15.0	0.62	0.13
1968	2.46	14.5	0.56	0.10
1969	2.35	13.8	0.55	0.06
1970	2.25	13.7	0.54	(0.21)
1971	2.43	13.2	0.58	(0.65)
1972	2.31	13.1	0.56	(0.15)
1973	2.28	13.6	0.63	(0.48)
1974	3.26	17.4	0.82	0
1975	3.60	30.1	0.98	0.19
1976	3.83	42.9	1.04	(0.15)

[a]Oil prices are based on 35° API Redwater crude. The netback value is the field price less a royalty. The oil royalty calculated is based on a high producing well (10,000 barrels per month). If two royalty schemes were in effect during the year, the higher royalty rate is used. The gas price is the average sales revenue per Mcf for the year. Current dollar values are deflated to constant 1971 dollars by the Canadian GNP price deflator.

(a) Values are for the expected average discovery size; this is assumed to equal the primary recoverable reserves from a pool equal in size to the average from the previous year. Reserve estimates are the 1976 appreciated reserves reported by the ERCB, so that firms are assumed to have information about the discoveries in the province in the previous year, and to foresee pool appreciation.

(b) It is assumed that a pool has a life of 25 years, and that the annual decline rate is 10 percent. The initial output rate, then, is 10.9 percent of the proved reserves.[7] Net present value clearly depends upon the number of wells required to drain the pool. This will, of course, vary considerably from pool to pool depending upon specific reservoir characteristics the desired level of output and maximum rate limitations. In column 3 of Table A.2 it was simply assumed that an individual well is capable, when production commences, of producing 500 barrels per day.

(c) Tax regulations anticipated over the life of the pool were assumed to be those in existence in the year the pool was discovered. The average royalty rate in this initial year of operation was assumed to hold over the life of the pool.

(d) Development drilling and exploratory well costs were assumed equal to the average observed cost of a well in Alberta in that year. Other development costs were assumed equal to 37 percent of development drilling costs, approximately the average value from 1947 through 1970. Operating costs were arbitrarily set at $1000/well/month. (All costs were expressed in dollars of 1971 purchasing power, as deflated by the GNP price deflator.) Development expenditures were assumed to be incurred in the year after discovery. A real discount rate of 10 percent is used.

(e) Column 4 of Table A.2 is a modification of Column 3 to make some allowance for the restrictions of the Alberta market demand prorationing scheme. There were two main effects over the period under study. First, output levels, except for wells with very low productivity, were held below capacity. Secondly, prior to revisions to the scheme in 1964, there were incentives to drill an unnecessarily large number of development wells to produce allowable volumes. (There is an obvious interaction between these two effects of the scheme, since a greater number of development wells meant a greater production capacity.) Column 4 includes two modifications to the data input used in column 3 to allow for the effects of prorationing. First, we examined ERCB data showing the ratio of average daily oil production in the province each year to daily capacity at year end. In each year the ratio, to the nearest decimal, was multiplied by the initial output figure for column 3, and the pool lifetime was extended proportionately. Second, after 1964, the number of development wells was reduced by one-fifth (where possible).

A second adjustment was made to column 4 to reflect the expectation of success in exploratory drilling. The ratio of oil successes to total exploratory wells in the previous year was calculated and the exploratory well cost was divided by this success ratio to give a total exploratory well cost, including dry holes.

It is obvious that the assumptions utilized to calculate the discovery value of oil reserves (as shown in columns 3 and 4 of Table A.2) are rather arbitrary and could be modified in a great number of ways. For example, allowance could be made for much more elaborate methods of estimation of expected prices or discovery size. Some weighted average of past values might be used, or a 'rational expectations' approach, at least for the earlier years, utilizing actually observed values for prices, costs and regulatory variables. More sophisticated treatment of the cost and tax variables are possible: the drilling costs are averages for all Alberta, including gas wells and wells drilled to all depths; no allowance was made for completion costs of successful exploratory wells or for dry development wells; the royalty rates have not been adjusted as production decline reduces future output levels, and so on. (Some of these adjustments would be very difficult to make. Exploratory wells drilled in Alberta, for instance, cannot readily be classified into 'oil' as opposed to 'gas' wells, and no annual cost-depth relationships are available.) The calculations in Table A.2 are based upon an estimate of the average expected discovery size. There is, however, no necessity that average expected profitability should be that of the single discovery of average expected size. (That is, there need be no strict relationship of positive proportionality between expected profit and expected size.) Moreover, the behaviour of the industry need not be guided by expected profit values, since companies may not be risk neutral or may place particularly heavy emphasis upon the maximum result observed. Finally, the calculations were based upon appreciated primary recoverable reserves. Such values were not observable to the industry in the year after initial discovery, both due to confidentiality regulations for new discoveries and because actual appreciation takes place over time. Nor are enhanced recovery reserves considered, even though companies may have had some expectation of this occurrence.

It is difficult to see how such ambiguities in estimation of a value for oil reserves can be eliminated, and hence a number of possible candidates for an oil revenue figure exist, and could be viewed as reasonable. If this data is to be used as input into an econometric

TABLE A.3

COMPARISON OF VARIOUS MEASURES OF REAL PER UNIT OIL AND GAS VALUES (1967 = 100)

	(1) Oil: Average Wellhead Price	(2) Oil: Wellhead Price Less Royalties	(3) Oil: Value in Ground I	(4) Oil: Value in Ground II	(5) Natural Gas: Wellhead Less Royalty
1947	n/a		n/a	n/a	8[illegible]
1948	n/a	215	n/a	n/a	7[illegible]
1949	195	178	302	538	6[illegible]
1950	191	179	282	485	6[illegible]
1951	158	137	232	623	5[illegible]
1952	133	122	132	423	4[illegible]
1953	135	128	142	477	4[illegible]
1954	141	133	148	546	5[illegible]
1955	129	125	140	269	4[illegible]
1956	131	121	137	77	4[illegible]
1957	133	126	145	231	5[illegible]
1958	126	121	129	200	4[illegible]
1959	114	113	116	131	3[illegible]
1960	111	110	113	169	3[illegible]
1961	106	11	103	-436	9[illegible]
1962	102	115	103	-92	9[illegible]
1963	110	115	113	138	10[illegible]
1964	112	112	113	123	10[illegible]
1965	109	109	110	136	1[illegible]
1966	106	104	106	131	1[illegible]
1967	100	100	100	100	1[illegible]
1968	97	97	96	77	9[illegible]
1969	93	93	89	46	9[illegible]
1970	90	89	87	-161	9[illegible]
1971	95	96	94	-500	8[illegible]
1972	90	91	90	-115	8[illegible]
1973	101	90	102	-389	9[illegible]
1974	145	128	132	0	11[illegible]
1975	165	142	156	146	2[illegible]
1976	175	151	166	-115	2[illegible]

SIMPLE CORRELATION COEFFICIENTS BETWEEN REAL VALUE MEASURES:

	(1)	(2)	(3)	(4)	(5)
1) Oil: Average wellhead price	1.00				
2) Oil: Wellhead price less royalties	.97	1.00			
3) Oil: Value in ground I	.91	.93	1.00		
4) Oil: Value in ground II	.59	.62	.64	1.00	
5) Natural Gas: Wellhead price less royalties	.25	.16	-.06	-.28	1.00

time series analysis, it is the changes in value over time which are critical. Table A.3 shows this information for a number of the value series mentioned in this study, particularly oil values, all indexed so that the 1967 value equals 100. It can be seen that the different price series do show different movements over time. At the bottom of the table is a matrix of simple correlation coefficients between different pairs of price series. The netback prices of oil and natural gas moved quite differently over this period. Moreover, the oil price series ('Value in Ground II') which is designed to incorporate the influence of variables such as changes in drilling costs, changes in average discovery size, variations in the success rate, and prorationing, income taxes and changes in other regulations, is not close to perfectly correlated with the other price series. This suggests that great care must be taken in formulating a price series for petroleum, if the variable is designed to serve as a proxy for expected profitability. (Given the arbitrary assumptions involved in calculating the 'Value in Ground II' numbers, in particular the complete absence of any allowance for natural gas successes, the actual correlation coefficients in Table A.3 should not be taken precisely; but the importance of careful definition of price variables is evident.)

Finally, it has been assumed that investment is strongly conditioned by expected profitability; it is commonly further assumed that current prices and profitability are a good approximation of expected profitability. This is, of course, a very rudimentary assumption about the formation of expectations. Recent empirical work suggests that the process is much more complicated, but no firm conclusions have been reached, and it is not at all evident how best to incorporate these complications in econometric analysis.[8] Accordingly, most empirical work uses current, or recent, price information, with or without a formal lag structure, as a measure of expected prices.

Footnotes

[1]This appendix reviews major regulations for the period from 1947 through 1978. It does not summarize the major features of the federal National Energy Program (NEP) of October 1980 or the Alberta-Ottawa Energy Agreement of September 1981. For a more thorough review of the fiscal regulatory environment after 1974 see W. B. Friedenberg, Z. C. Slagorsky and A. J. Walsh "Government Incentives in Canada's Petroleum Industry", (Calgary: Canadian Energy Research Institute), Working Paper 80-1, March 1980.

[2]The summary does not discuss carry forward provisions, regulations for averaging and other details of this nature. Nor is mention made of the lower tax rate on the first small amount of corporate taxable income. Also excluded are 'special' depletion allowances. (For example, from 1978 through 1980, there was a special 50 percent earned depletion allowance, with a ceiling of 50 percent of net production profits, for enhanced recovery expenditures; as well, from 1977 through 1980, there was a 66-2/3% depletion allowance for exploratory drilling costs in excess of $5 million on a well.) Nor are precise capital consumption expenditures for all classes of capital shown; most common has been 30 percent deductibility on a declining-balance basis.

[3]Since the NEP and Alberta-Ottawa energy agreement, it has become necessary to consider the new federal taxes (i.e., the petroleum and gas revenue tax and the incremental oil revenue tax, if applicable), and the petroleum incentives program, as well as the changes in income tax regulations (particularly the proposed phase-out of the conventional depletion allowance and 'super-depletion', and the requirement that bonus bids be depreciated on a 10 percent declining balance basis).

[4]It will be assumed throughout this paper that no significant substitution possibilities among inputs are possible. For interesting attempts to incorporate input substitution effects directly see Epple (1975) and Uhler (1979).

[5]This approach considers only the price and royalty terms of the NPV equation, (i.e., of the revenue and royalty terms,

$$(1 - r_o)p_o \sum_{t=o}^{T} q_t (i + i)^{-t})$$

and calculates only the $(1 - r_o)p_o$ part of this expression.

[6]For a detailed evaluation of some of the costs of the Alberta market demand prorating schemes prior to 1964 see G. C. Watkins (1971).

[7]Assume that all of the estimated proven reserves are lifted, and that exponential decline governs production from the pool throughout its life. Then the following table tells the proportion of the oil removed from the pool during the first year of production for different combinations of the decline rate (d) and the lifetime of the pool (T):

d \ T	20	25	30	∞
5	7.9%	7.0%	6.4%	5%
10	11.6%	10.9%	10.5%	10%
15	15.8%	15.4%	15.2%	15%

T

d

It can be seen that as the decline rate becomes larger, or as the expected lifetime of the pool becomes greater, the initial output rate comes closer to d% of the initial reserves.

[8]For a recent review of work in this area see J. Chan-Lee "A Review of Recent Work in the Area of Inflationary Expectations," Weltwirtschaftliches Archiv 1980 (116), pp. 54-85.

APPENDIX B

CHARACTERISTICS OF ALBERTA OIL PLAYS

Appendix B

CHARACTERISTICS OF ALBERTA OIL PLAYS

B.1 Introduction

The economics of crude oil production is indissolubly wed to the underlying geological distribution of petroleum. As noted in the text, however, the 'geological distribution of oil' has three guises: (i) the actual distribution in nature, which is never known completely; (ii) the expectations of individual petroleum companies, which will differ somewhat from company to company; and (iii) available information from discovered deposits about the underlying geological distribution. The highly competitive nature of the oil exploration business means that companies have a very strong interest in seeing that their current geological expectations do not become public knowledge.

This study of the economics of Alberta crude oil discoveries is based on the premise that an explicit recognition of geological realities is desirable. Such recognition occurs, in Chapter 3 of this study, through the particular form of the statistical equation used to 'explain' the historical process of oil discovery: it is argued that the underlying geological conditions make diminishing marginal returns the norm.

This appendix addresses itself to a more formal consideration of the process of generating geological knowledge in the petroleum industry. The hypothesis underlying the appendix is that the prime source of expectations about prospective petroleum finds is the character of previous finds. In a statistical sense, successful discoveries are viewed as elements in a sample drawn without replacement from the underlying population, and the sample is used--explicitly or implicitly--to estimate those population parameters and indicate the dimensions of the next sample item drawn.

This appendix, then, is concerned with the sense in which such pool data can be taken to represent sample data, which can then be used to form statistically meaningful expectations.

ERCB regulations require that technical data be made public within one or two years of discovery of a pool; therefore such

information will form a basic part of that available to the industry generally. The underlying data base for this study is the statistical bank of individual pool data drawn from ERCB reports and files for discovered oil pools in seven Alberta oil plays.[1] (Appendix C includes summary data for these pools and plays, including maps of their locations, lists of the individual pools in each play, and records of the appreciation of reserves in each play.) Indications are that the records of discoveries for these plays are pretty well complete now. Certainly the likelihood of very large new finds in any of the seven plays is regarded as very low.

This appendix includes three main sections: first, a brief review of several key aspects of the various oil plays in order to indicate the differences between them; second, consideration of the extent to which data about individual pools may be viewed as a useful statistical sample of an underlying population; and third, some preliminary observations on correlations between sample statistics.

B.2 Comparative Characteristics of Different Plays

Tables B.1 through B.3 show some statistical features of seven Alberta oil plays. In Table B.1 aggregate characteristics of the plays are presented to demonstrate their relative importance (the recovery percentages may be interpreted as a weighted average); in Table B.2 certain characteristics of the average pool in the play are given to illustrate some differences amongst plays (the recovery percentages here are the average of the various pools, or the unweighted average); and in Table B.3 some indication of the diversity of results within each play is given. As the tables indicate, there are both differences between plays and wide variations in the characteristics of individual pools within a play. Of the seven features of individual pools which are considered--area, thickness, volume of oil in place, volume of recoverable oil, recovery percentage, porosity and depth--only the last two show little variability within a play.

B.3 Discovered Pools as a Statistical Sample

In review, an underlying actual physical distribution of oil pools exists in any petroleum play, and from that underlying distribution single observation samples are taken as discoveries are made. Obviously these samples tell us something about the underlying distribution; at the very least they give the characteristics of one

TABLE B.1

COMPARATIVE PLAY CHARACTERISTICS: AGGREGATE LEVELS

	Year of Discovery	No. of Pools	Oil in Place (10^6 stb)	Primary Recovery Factor (%)	Enhanced Recovery (ER) Factor (%)	No. of Pools with ER	Proportion of Pools with ER (%)
Leduc, D-3	1947	71	4,554	57.7	4.0	5	7
Nisku, D-2	1947	58	1,281	43.7	5.2	7	12
Viking	1949	39	1,124	15.4	12.2	7	18
Cardium	1953	59	9,141	10.6	8.9	9	15
Granite Wash	1955	15	161	26.6	0	0	0
Beaverhill Lake	1957	20	6,136	16.3	27.1	14	70
Keg River[a]	1965	407	3,525	31.2	14.3	75	18

[a]A number of Keg River pools found in the same year were aggregated since the play includes a very large number of separate 'pinnacle reefs'. For this reason, comparative data related to average pool size, etc., are not readily calculable from the data base for this study. Also, a number of separate accumulations of oil are partially propelled by the same underlying water drive, so that enhanced recovery schemes in the Rainbow-Zama area often apply to more than one pool.

The Keg River data include several pools outside the far northwest corner of the province, in the Nipisi, Mitsue, Utikuma Lake area. Excluded are a number of pools in the Rainbow-Zama fields, but in formations other than the Keg River (most of these lie in the 'Muskeg' formation, some in the Slave Point).

TABLE B.2

COMPARATIVE PLAY CHARACTERISTICS: AVERAGES

	Pool Area (acres)	Pool Depth (feet)	Pool Porosity (fraction)	Pool Thickness (feet)	Average Oil-in-Place (10^3 stb)	Average Recoverable Oil (10^3 stb)	Recovery Factor (%)
Leduc, D-3	2,840	6,220	.074	59.7	64,139	39,553	39.8
Nisku, D-2	2,331	5,593	.057	29.6	22,092	10,789	30.3
Viking	6,815	5,291	.143	7.2	28,811	7,984	19.0
Cardium	12,479	6,562	.116	16.3	154,940	30,205	9.7
Granite Wash	1,247	4,860	.107	10.3	10,726	2,857	13.5
Beaverhill Lake	18,056	9,037	.071	35.1	306,775	133,171	32.2

TABLE B.3[a]

COMPARATIVE PLAY CHARACTERISTICS

	Pool Area		Depth		Porosity		Thickness		Oil-In-Place		Recoverable Oil		Recovery Factor	
	Range	S/M[b]	Range	S/M	Range	S/M	Range	S/M	Range	S/M	Range	S/M	Range	S/M
Leduc D-3														
min.	15	2.14	3,208	0.24	0.028	0.26	8	1.25	750	2.84	2	3.00	0.4	0.63
max.	37,500		11,593		0.12		489		1,300,000		806,000		84	
Nisku D-2														
min.	130	2.11	1,966	0.19	0.018	0.39	4	0.58	219	2.59	1	3.16	0.2	0.65
max.	25,599		7,787		0.14		77		357,000		239,000		68	
Viking														
min.	80	3.02	2,570	0.36	0.058	0.37	2	0.58	203	3.46	1	3.23	0.2	0.73
max.	123,612		8,510		0.264		22		592,000		137,700		50	
Cardium														
min.	20	5.00	3,229	0.20	0.039	0.23	3	1.11	365	6.20	1	6.42	0.1	0.63
max.	470,920		9,060		0.160		104		7,430,000		1,500,000		34.3	
Granite Wash														
min.	160	n/a	5,008	n/a	0.093	n/a	3	n/a	287	n/a	12	n/a	1	n/a
max.	9,350		4,704		0.200		18		90,700		27,200		30	
Beaverhill Lake														
min.	320	1.32	7,485	0.10	0.050	0.17	10	0.55	1,050	1.49	81	1.53	1	0.51
max.	101,280		11,269		0.092		69		1,910,000		803,000		60	

[a]Units of measurement are the same as in Table B.2

[b]S/M is the ratio of the calculated standard deviation of values to the mean value: a relatively small number here means that most pools have values close to the mean value.

individual item in the population. The extent to which a sample--or the samples up to this time--can tell us about the population as a whole (or about the remaining, unsampled, part of the population, which is our real interest) is a function of two things:

- Knowledge drawn from the sample items is useful only to the extent that it allows us to hypothesize about the distribution of the underlying population.
- The method by which sampling was undertaken is important; in particular, classical techniques of statistical inference are valid only if the sample is random, in the sense that each item has an equal chance of being selected.

B.3.1 Data Base

For each pool, the following physical parameters were available.

1. Year of discovery
2. Porosity (fraction)
3. Area (acres)
4. API (degrees gravity)
5. Pay thickness (feet)
6. Water saturation (fraction)
7. Gas/oil ratio (cf/bbl)
8. Initial pressure (psia)
9. Pool depth (feet)
10. Oil in place, year of discovery estimate (10^3 stb)
11. Oil in place, 1976 estimate (10^3 stb)
12. Appreciation factor (i.e., 11 ÷ 10)
13. Primary recoverable reserves, year of discovery estimate (10^3 stb)
14. Primary recoverable reserves, 1976 estimate (10^3 stb)
15. Appreciation factor (i.e., 14 ÷ 13)
16. Recovery factor, year of discovery estimate
17. Recovery factor, 1976 estimate
18. Reserves per acre foot, oil in place
19. Reserves per acre foot, primary recoverable oil
20. Enhanced recovery (0 if no scheme in place, otherwise 1)

Except for year of discovery reserve estimates, all data are as indicated by the ERCB 1976 Reserves Report; it is, therefore,

implicitly assumed that the estimated physical variables--e.g., depth, thickness, porosity--for any pool are relatively fixed over time.

B.3.2 Random Sampling

For any play there are, as of the end of the period considered (i.e., December 1976), a certain number of pools discovered (sample observations). The distribution of sample attributes for any play were 'drawn' in a particular order, that is, the order of pool discovery. If the observations on any particular attribute were made randomly we would expect that each item remaining in the unsampled population would have as much chance of being sampled as all others remaining; as a result there would be no real pattern in the order of sampling of that attribute.

To test for randomness, a very simple statistical test was undertaken--commonly referred to as 'runs above and below the median'.[2] If the sample were truly random one would expect each value to be as likely to be above as below the median, and long runs of contingent values either above or below the median to be rare. This test is applicable if n is small and even, in which case sample statistic (Z) accords with the binomial distribution; if $n \geq 25$, Z follows the normal distribution. As a result of these restrictions, this test could not be applied to the Slave Point, Granite Wash or Sulphur Point plays; it was applicable to the others, and the results are presented in Table B.4. Randomness for the various attributes is indicated for all attributes except area (the only exception is the Beaverhill Lake play which is not quite statistically significant), reserves figures (again with minor exceptions), and the appreciation factor for recoverable reserves.

The results are compatible with a commonly observed phenomenon in the petroleum industry: the larger pools in terms of area and reserves tend to be discovered first. The appreciation factor results suggest that it is the largest pools (i.e., the earlier discovered) which tend to have reserve estimates that are significantly increased over time. Of course, the pools discovered earlier have also had a greater number of years in which appreciation might occur. This is discussed in more detail in Appendix C. The indicated randomness for the other pool attributes suggests that a company can regard the values from various pools discovered up to that date as a random sample of the population, and therefore apply classical statistical techniques to estimate the likely value of that variable in a new successful well. Some of these attributes are important in assessing the likely reserves of oil (e.g., porosity, water saturation, thickness) or recovery

TABLE B.4

VALUES OF Z FOR TEST OF RUNS ABOVE AND BELOW THE MEDIAN[a]

	Leduc (D-3)	Nisku (D-2)	Viking	Cardium	Beaverhill Lake[b] (No. of runs)
Attribute[c]					
2. Porosity	-0.12	-2.12	-3.09*	0.39	12
3. Area	-3.47*	-3.71*	-4.06*	-6.43*	7
4. API	-0.36	-1.32	0.81	-1.71	13
5. Pay thickness	-1.08	0	-.049	-0.92	8
6. Water saturation	-1.31	0	2.11	0.92	10
7. Gas/oil ratio	-2.51	-1.85	-1.14	-0.92	14
8. Initial pressure	-2.03	-2.12	-0.49	0.66	10
9. Pool depth	-2.51*	-2.65	-0.49	-0.66	10
10. Oil in place, YOD	-4.90*	-2.38	-0.49	-6.96*	5*
11. Oil in Place, 1976	-3.94*	-4.77*	-4.71*	-6.43*	7
12. Appreciation factor, YOD	-3.23*	-4.24*	-4.71*	-4.07*	9
13. Recoverable reserves, YOD	-4.90*	-1.85	-0.49	-7.49*	5*
14. Recoverable reserves, 1976	-4.42*	-4.24*	-4.71*	-6.96*	5*
15. Appreciation factor	-4.46*	-4.77*	-4.71*	-4.07*	7
16. Recovery factor, YOD	-0.12	-2.91	-2.43	-1.97	10
17. Recovery Factor, 1976	-2.03	-1.06	-0.49	0.13	10
18. Oil in Place per acre foot	0.84	-0.53	-1.79	-4.33*	11
19. Recoverable Reserves per acre foot	-0.12	-0.79	-2.43	-0.13	13

[a]The critical value of Z at the 99 percent level of confidence is 2.58. If the absolute value of the Z statistic exceeds the critical value the series may be considered non-random.

[b]There were only 20 observations here, so the binomial distribution (with probability = 0.5) was used. If random, more than 6 runs are expected.

[c]Attributes indicated non-random by this test are noted with an asterisk (*).

factors (initial pressure, gas-to-oil ratio): to the extent that most of these are apparently random, one could suggest that the critical non-random element underlying the oil reserves value is the area of the pool. It might also be noted that some of the variables are related directly to the economics of the venture (e.g., gas-to-oil ratio, water saturation, specific gravity): again, if these are to be regarded as randomly generated by discoveries up to the date of drilling a new venture, their expected value in a subsequent discovery may be estimated from the sample to date.

B.3.3 Distribution of Population Parameters

If we assume that for the various plays considered we now have relatively complete information about the population, the distribution of any attribute within each play can be examined to see if it displays any regularity. Numerous theoretical distributions are possible: we have examined only two--the normal and the lognormal. The results are given in Table B.5 for the five larger oil plays: Leduc (D-3), Nisku (D-2), Viking, Cardium and Beaverhill Lake. In an important respect the results of the table corroborate a common finding in the statistical analysis of the size distribution of petroleum deposits: reserves and area are log normally distributed. As can be seen, the tests are somewhat inconclusive for most of the other variables. Porosity appears to be normally distributed for all plays, and thickness log normally. (The log normality of reserves may derive from the log normality of area and/or thickness: however, only in the Beaverhill Lake play is there any significant positive correlation between area and thickness.) In four of the five plays, the gas-to-oil ratio and depth can be approximated by a normal distribution (although log-normal cannot be rejected for depth); in three of the five, water-saturation, initial pressure, and reserve/acre foot may be approximated by a normal distribution. Neither distribution appears appropriate, in even a majority of cases, for specific gravity.

The above tests are of some importance in assessing the expected values of particular random variables, since the average value of a sample drawn from a normal distribution is an estimate of the mean of the distribution, and the expected value of a sample drawn from a normal distribution is the mean of that distribution. Therefore, for such variables, an explorer drilling a new well to a geological formation could use the mean value of discoveries to that date in that formation as an estimate of the value for the pool he would find if his well is successful.

TABLE B.5

TESTS FOR NORMALITY AND LOG NORMALITY
(Chi-square values)[a]

	Normal					Log-Normal				
	Leduc (D-3)	Nisku (D-2)	Viking	Cardium	Beaverhill Lake	Leduc (D-3)	Nisku (D-2)	Viking	Cardium	Beaverhill Lake
2. Porosity	2*	6*	6*	8*	2*	3*	10*	1*	15	2*
3. Area	166	85	128	597	8*	2*	5*	7*	9*	3*
4. API	17	15	6*	16	34	26	15	6*	20	34
5. Pay thickness	66	17	5*	41	2*	5*	3*	2*	3*	1*
6. Water saturation	40	4*	16	8*	9*	11*	16	21	15	4*
7. Gas/oil ratio	65	2*	7*	3*	5*	39	59	11*	59	14
8. Initial pressure	42	15	11*	9*	8*	109	153	26	188	68
9. Pool depth	31	13*	5*	9*	3*	14	11*	5*	7*	3*
10. Oil in place, YOD	173	100	30	3,270	38	6*	2*	4*	8*	3*
11. Oil in place, 1976	231	263	583	4,072	9*	12*	2*	2*	6*	2*
12. Appreciation factor, YOD	265	894	2,980	253	12*	40	45	21	11*	6*
13. Recoverable reserves, YOD	373	63	86	8,219	122	7*	1*	4*	8*	7*
14. Recoverable reserves, 1976	326	432	550	4,470	8*	1*	2*	6*	2*	1*
15. Appreciation factor	792	1,070	1,983	782	13*	6*	18	24	16	3*
16. Recovery factor, YOD	5*	31	5*	22	9*	48	18	15	79	22
17. Recovery factor, 1976	24	7*	5*	34	25	74	26	20	81	82
18. Oil in place per acre foot	2*	4*	46	188	5*	6*	10*	5*	21	3*
19. Recoverable reserves per acre foot	13*	12*	31	n/a	2*	24	15	5*	38	8*

[a]The critical Chi-square value at a 1 percent level of confidence is 13. Therefore, we can reject the hypothesis that the distribution is normal (or log-normal) at the 1 percent level only if the value in the table exceeds 13. (At a 5 percent level of significance, the critical value is 9.5.)

Variables which are reasonably approximated by a normal (log-normal) distribution on this basis are indicated with an asterix (*). Attributes with little variability, or very low average values, may be reasonably well approximated by both normal and log-normal distributions.

B.3.4 Conclusion

In conclusion, three somewhat separate classes of variables have been found.

First, variables such as area and reserves are not randomly generated for the pools in a particular play, so classical techniques of statistical inference may not apply. (Strictly speaking, however, the classical linear regression model is based upon certain assumptions of normality in the error terms of underlying variables.) To estimate population parameters, two courses of action are open. One is to apply an 'eclectic' approach, to see what trends actually have been in the discovery process (e.g., by a linear regression model), while indicating that the trends were not generated in a random manner. The second approach is to hypothesize that the discovery process is random, but not in terms of selection of pools. For instance, one might argue that the probability of picking any particular acre lying above an oil pool is a random variable; the larger the pool then the greater its chances of being selected (discovered). We will not pursue this latter approach here but suggest it for consideration. In actual practice, it seems likely that geophysical activities will provide evidence on both the area and thickness of potential drilling targets.

Second, some pool attributes do appear to exhibit the characteristics of random selection and the underlying population does appear to follow a normal (or log-normal) distribution (examples are porosity, thickness, gas-oil ratio, and depth). In such a case we can approximate the expected value in a new successful venture by the average of earlier successes. This may be desirable if it is argued, for example, that the profitability of a well depends on the gas-oil ratio.

Third, some pool attributes exhibit randomness, but not normality. In such a case it is possible that the distribution of population statistics can be approximated by some other distribution. If this is not the case, then there is no 'expected' value for the variable in the sense in which classical statistical theory uses the word 'expected'; however, companies engaged in exploratory activity will formulate some subjective expectation. It seems reasonable to suggest that they will derive their expectation either from the average of values for already discovered pools or from the last single value which they observed. If the former, then the expectational process is the same for this class of attributes as for the random, normal ones just discussed.

8.4 Simple Correlations Among Variables in Oil Plays

The data base of attributes for oil pools within a play allowed the calculation of a simple correlation matrix for all twenty variables: detailed results are available from the authors. Simple correlation coefficients must be used with caution, of course, especially if there is no complete theoretical model from which anticipated positive or negative interrelationships can be hypothesized. Variables may move together although there is no causal link, and if two variables are linked but in conjunction with other variables, a simple correlation coefficient may not be indicative at all of this connection. Still, these simple correlations do yield suggestive information.

- The correlation coefficients between year of discovery and 1976 reserve estimates are not uniformly high, confirming that the year of discovery estimate of pool size is often a poor indicator of the magnitude of a field, even with respect to ranking different pools in a single play.

- The correlations between 1976 recoverable reserves and the appreciation factor for recoverable reserves are also variable (sometimes negative) and generally not too large: that is, on the basis of all pools considered there is no clear tendency for the largest reserves to undergo the greatest appreciation. At the same time, the earlier result of 'non-randomness' in the appreciation factors must be kept in mind.

- High correlation coefficients are found between pool area and 1976 estimates of oil volume, and these variables are negatively correlated with time. It will be recalled that the tests for 'randomness' and 'normality' showed that pools of larger area and larger reserves tended to be found first.

The enhanced recovery variable was a simple binary variable (with a value of 1 if an enhanced recovery scheme was in effect in 1976, otherwise zero), so that simple correlation coefficients do not have as precise significance here. However, as might be expected, for most of the plays (5 of the 6 with such schemes in place) there was a positive coefficient (higher than 40 percent) between this variable and the area of the pool--an economy of scale factor is suggested.

Finally, the simple correlation coefficients did confirm certain physical interrelationships which would be expected: initial pressure was highly positively correlated with depth and with the gas-to-oil ratio (except in the Granite Wash play).

Numerous other high positive or negative correlation coefficients exist, but none that are consistently high across all plays, nor any of obvious importance within a single play.

B.5 Conclusion

This appendix has presented some simple statistical data about major Alberta oil plays. The most important observations can be summarized as follows:

- different oil plays have distinct characteristics;
- the timing of discovery of pools is not random, with the larger pools (in area and reserves) tending to be found first;
- the reasonableness of accepting a highly skewed distribution of pools by size within any oil play is confirmed;
- for pool attributes other than size, the mean value for already discovered pools seems an appropriate estimate of the expected value for a new success.

Footnotes

[1]Very small discoveries may be classified as dry or noncommercial and hence are excluded from the sample.

[2]For a description of the simple statistical tests used in this appendix see Y. Chou, Statistical Analysis (London: Holt Rinehart and Winston, 1970), pp. 440-456.

APPENDIX C

CRUDE OIL RESERVES BY GEOLOGICAL HORIZON: HISTORY AND APPRŁCIATION

Appendix C

CRUDE OIL RESERVES BY GEOLOGICAL HORIZON: HISTORY AND APPRECIATION

The basic unit of investigation in Chapter 3 is the oil in an exploratory 'play'--defined as reserves accruing commercially within the confines of a particular geological horizon. Implicit in this definition is the distinction between the physical extent of the formation and the commercial extent of the play.

To set the purely physical environment to which we will be referring, Figure C.1 presents a simplified geological cross-section of Alberta. The relative oil bearing importance of specific geological horizons is summarized in Figure C.2. As shown, the majority of the total Alberta crude oil reserves are attributable to a relatively small number of plays: the three most significant (Leduc, Cardium and Beaverhill Lake) comprise 55 and 63.6 percent of the total estimated oil-in-place and recoverable reserves, respectively; all seven selected formations yield 71.5 and 86.7 percent. A brief historical sketch of the discovery and locale of these plays follows.

C.1 History of Discovery

Although there was some earlier activity in the Western Canadian Sedimentary Basin (e.g., at Turner Valley and Norman Wells), the 1947 Leduc discovery was the first significant development. Other major plays unfolded shortly thereafter, during the early and mid-fifties.

Figures C.3 through C.9 depict the geographical extent of the plays under examination. The dates within the circles denote the year of first discovery in the relevant horizon in that general area: the intent is not to be precise, but to give the reader an overall feel for the location of exploratory successes. It is immediately apparent that a great deal of geographical overlap occurs between plays; at different times, operators were drilling in the same geographical region but with different prime geological objectives. (Of course, companies test other geological formations through which the well passes in addition to that of prime interest.) Accompanying the maps is an abbreviated physical description of the formation itself, an indication of its

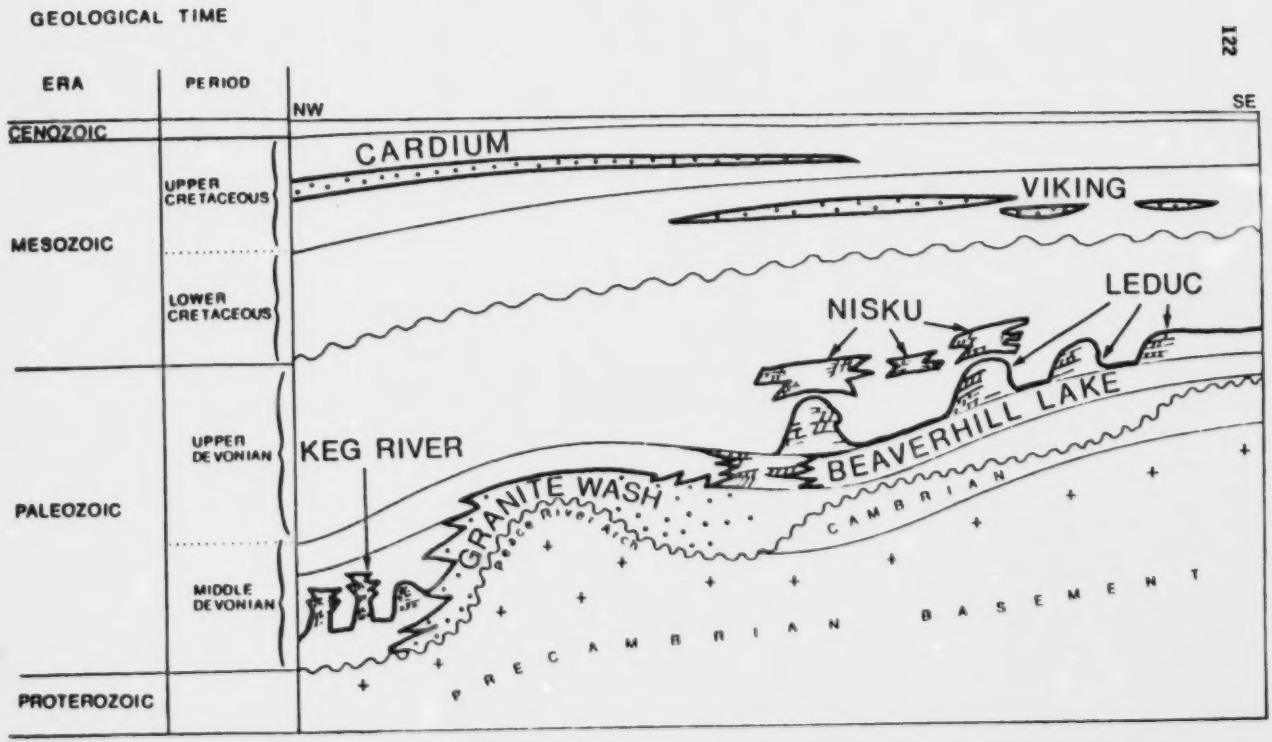


Figure C.1: Simplified Geological Cross Section Showing the Seven Plays

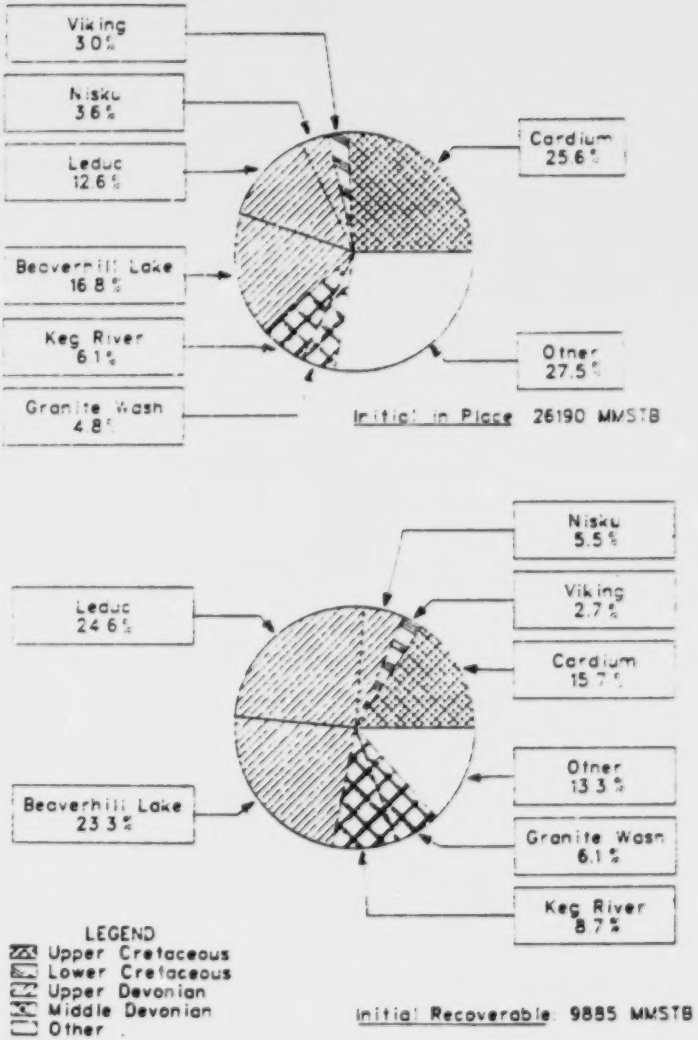


Figure C.2: Geological Distribution of Proved Reserves of Crude Oil

FIGURE C.3: Overview of Play Discoveries:
Leduc (D-3), Woodbend Group, Lower Upper Devonian

Physical Description: The Leduc formation is mainly a reef facies composed of light grey to dark brown crystalline limestone or dolomite.

Distribution: The thickness varies from 0 to more than 700 feet with pronounced changes in thickness occurring away from the reefs.

Discovery Well: 1947, Imperial Leduc No. 1, T.50 R.26 W.4M.

Expectations: ". . . origin of the porosity is not yet completely understood but the consensus favours the story that the reservoir is a fossil coral reef . . . appears to have the form of a broad structural nose . . . trends northeast and southwest."[7]

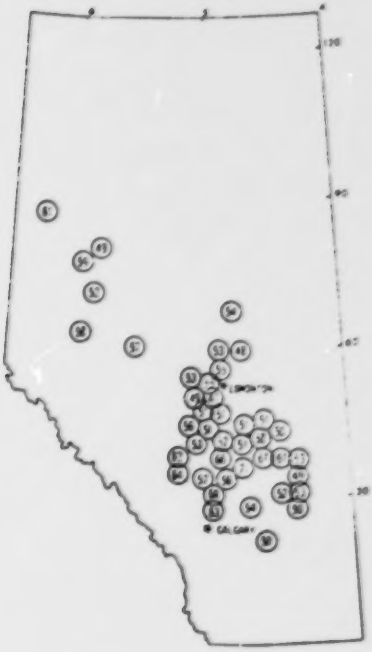


FIGURE C.4: Overview of Play Discoveries:
Nisku (D-2), Winterburn Group, Upper Devonian

Physical Description: The Nisku formation consists of light brown crystalline dolomite, variably silty and anhydritic.

Distribution: The thickness is consistent from 150 to 200 feet throughout Central Alberta except to the east where it is truncated by pre-Cretaceous erosion.

Discovery Well: Originally the Nisku was described as the D-2 zone in the early wells of the Leduc field, the first well being Imperial Leduc No. 3, Lsd.10 Sec.26 T.50 R.26 W.4M.

Expectations: (The Leduc (D-3) and Nisku (D-2) plays proceeded at the same time and from the upper Devonian formations; the Leduc play is the more significant in terms of volume and attracted more formal notice.)

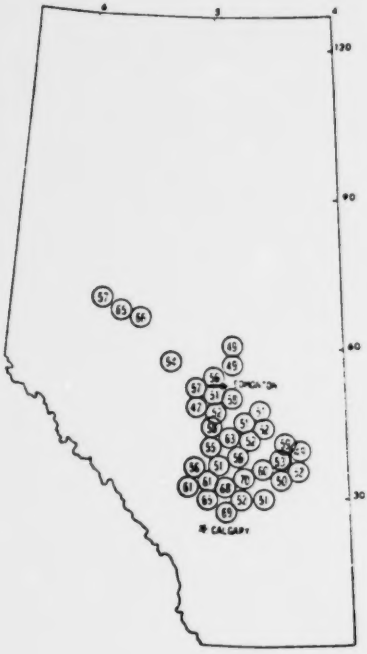


FIGURE C.5: Overview of Play Discoveries:
Viking, Colorado Group, Lower Cretaceous

Physical Description: The Viking formation grades from coarse sand to silty shale. The main component of the sand is clear quartz.

Distribution: The limit of the formation to the northeast is roughly a line drawn from Lac la Biche, Alberta, through Coleville and Swift Current, Saskatchewan, where the Viking shales out. The sand thickens from 60 to 200 feet to the southwest of this line.

Discovery Well: 1949, oil discovered in the Viking at Joseph Lake, 20 miles southeast of Edmonton.

Expectations: "The original Joseph Lake oil pool has been proven to be part of an accumulation of at least 35 miles long and two miles wide and is now called the Joarcam field. . . Since 1949 . . . several other discoveries of oil and gas in the Viking have indicated it to be a reservoir of some importance."[8]

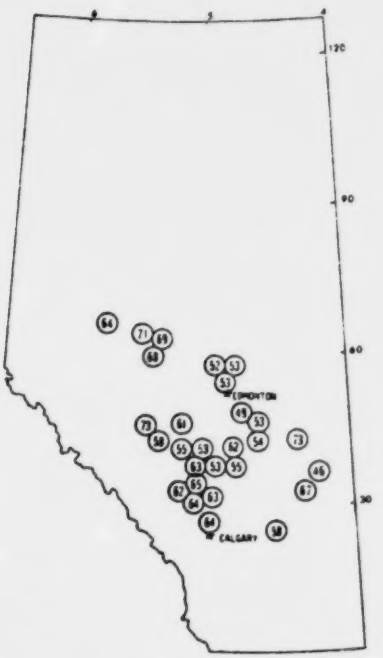


FIGURE C.6: Overview of Play Discoveries:
Cardium, Colorado Group, Lower Cretaceous

Physical Description: The Cardium formation consists of three sandstone members separated by dark shales.

Distribution: The thickness varies from 0 to over 440 feet. It has been reported as far south as Twp.14 in the foothills and Twp.17 in the mountains.

Discovery Well: July 1953, Socony-Seaboard Pembina No. 1.

Expectations: ". . . oil tended to accumulate in stratigraphic traps . . . this presented an entirely new target for exploratory drilling."[9]

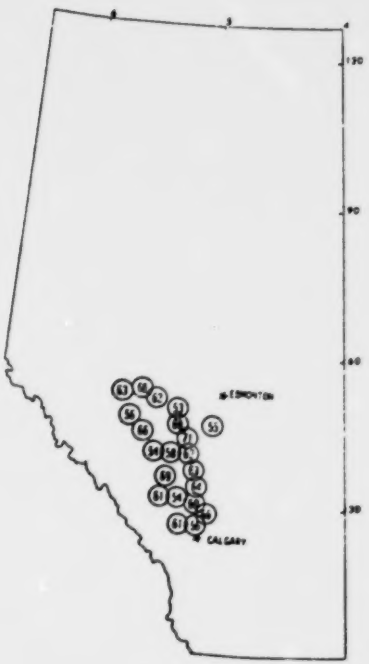


FIGURE C.7: Overview of Play Discoveries:
Granite Wash, Middle to Upper Devonian

Physical Description: The Granite Wash is composed of sandstone and shale. The sandstone is generally coarse and well sorted varying to conglomerate.

Distribution: The Granite Wash formation is mainly located to the north and east of the Peace River Arch. The thickness varies from 0 to 600 feet.

Discovery Well: 1955, Great Plains-Triad-Muskeg-Gilwood No. 1-9, Lsd.1 Sec.9 T.73 R.18 W.5M.

Expectations: ". . . the sands at the base of the Paleozoic throughout Western Canada will in time prove up prolific reservoirs of oil and gas. . . "[10]

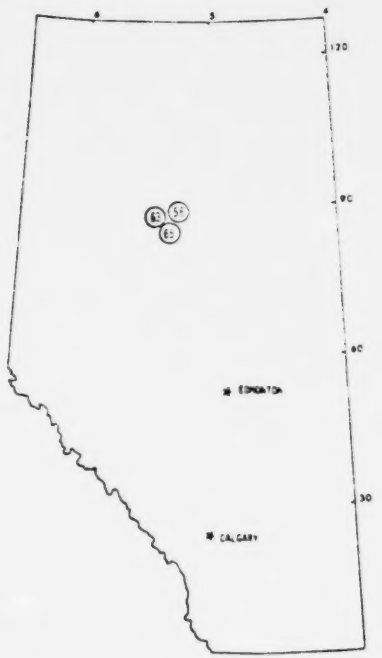


FIGURE C.8: Overview of Play Discoveries:
Beaverhill Lake, Middle and/or Upper Devonian

Physical Description: The Beaverhill Lake formation consists of a series of sedimentary cycles, usually three, alternating between lower fragmental and upper argillaceous limestones.

Distribution: The thickness of the formation is fairly uniform and is 722 feet thick in the typical well. The formation extends to the north and northeast and outcrops in the Athabasca and Clearwater River areas.

Discovery Well: Virginia Hills, Lsd.9 Sec.20 T.65 R.13 W.5M.

Expectations: "Until this time the Beaverhill Lake had not been considered an important producing formation."[11]

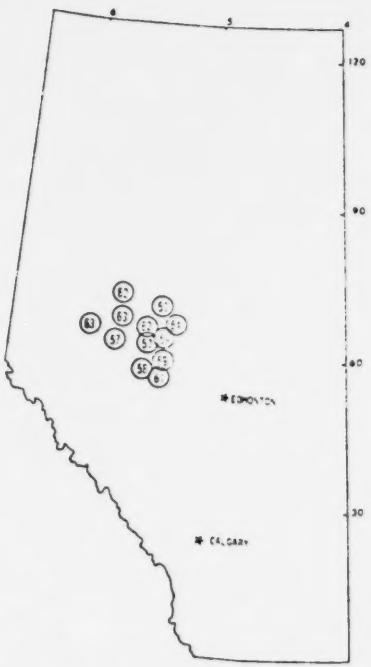


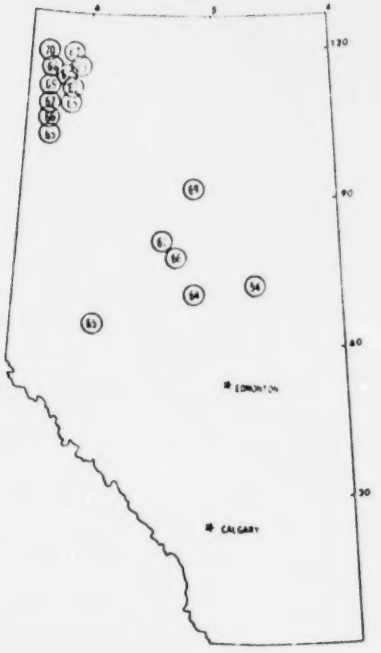
FIGURE C.9: Overview of Play Discoveries:
Keg River, Elk Point Group, Middle Devonian

Physical Description: The Keg River formation consists of crystalline dark brown to brownish grey dolomite and brown limestone. A transition from dolomite to limestone occurs to the north near townships 100 to 115 between the 5th and 6th meridians.

Distribution: The thickness varies from 80 to 300 feet thick in northwestern Alberta extending to the Great Slave Lake area.

Discovery Well: 1965, Rainbow West, Lsd.7 Sec.32 T.109 R.8 W.6M (Banff-Aquitaine).

Expectations: The discovery of oil in the Muskeg and Keg River formations at Rainbow Lake by Banff-Aquitaine was the first major discovery in Northern Alberta. At the time this was not only the 'most northerly discovery of substantial promise in Alberta' but also indicated that an area previously regarded as 'gas prone' had oil potential.[12]



physical extent, the name of the initial discovery well and its date, and the expectations of the industry as voiced at that time.[1]

C.2 The 'Reserve' Data Base

Unfortunately reserve data by geological horizon, in the form of a comprehensive time series, are not readily available. Any aggregation beyond the level of the individual reservoir usually proceeds utilizing the field as the appropriate unit rather than the exploratory play.

For this reason it was necessary to use the extensive pool by pool reserves statistics published annually by the ERCB, in which each pool is offically designated as producing from a certain formation.[2] The drawback is that the accuracy and consistency of these figures diminishes as one moves back to the early sixties. Completion of the time series required a painstaking search through the individual company reports filed, by regulation, at the ERCB.

In addition to the major physical reservoir characteristics listed in Appendix B, three types of yearly reserve estimates were compiled for individual oil pools belonging to the seven plays: initial oil-in-place, that recoverable by means of primary drive, and that attributable to enhanced recovery methods (the sum of these latter two being total recoverable oil).[3] The net result is a unique computerized data base, amenable to aggregation by field, by year of discovery, by various physical characteristics, or, most notably, by producing horizon (or by any combination of these attributes).

Table C.1 presents the annual cumulative reserve estimates summed over all of the reservoirs contained in our data base, based on 1976 estimates of pool reserves. For comparison purposes, the ERCB estimates for the province as a whole are given alongside, as well as the proportion of that total reflected in our data base. The proportion declines over time as more plays are discovered, but even by 1976 over 85 percent of the Alberta total recoverable reserves are included in these seven early exploratory plays (a ratio consistent with the 1976 ERCB estimate of the geological distribution of reserves as shown in Figure C.2). (The early variance in the two sources of estimates should not cause undue concern. By way of comparison, the Canadian Petroleum Association reserve estimates for this early period vary from +300 percent to -150 percent of the ERCB figures depending on the year. The 'correct' entry is difficult to determine mainly due to definitional incongruity and the lags involved in assessing new pools.)

TABLE C.1

ANNUAL RESERVE ESTIMATES: THE SEVEN MAJOR PLAYS

Total Number of Pools: 384[a]
Aggregated Reserve Data (MSTB)

Year	Oil-in-Place (OIP)	Recoverable			Percent of ERCB Total
		Primary	ENH	Total	Recoverable
1976	25922023	6466920	3369552	9836472	86.2
1975	25786831	6478781	3554184	10032965	87.1
1974	25757411	6482579	3566072	10048651	87.5
1973	25629197	6466080	3393097	9859177	87.7
1972	25505093	6511288	3388240	9899528	88.6
1971	25387855	6356260	3343638	9699898	87.8
1970	25178935	6242508	3408508	9651016	88.4
1969	25500863	6347029	3171748	9518777	89.1
1968	25335981	6321038	2820033	9141071	88.4
1967	24127002	6031709	2681730	8713439	90.9
1966	22743674	5481960	2632000	8113960	90.3
1965	22355134	4930411	2402300	7332711	90.5
1964	21111757	4641214	2433300	7074514	92.3
1963	16577349	4022298	709360	4731658	86.4
1962	15944919	3914810	523760	4438570	86.7
1961	14876892	4163373	406010	4569383	94.4
1960	13787908	4021287	242875	4264162	95.2
1959	11407190	3598845	184016	3782861	90.7
1958	9331757	3299934	86157	3386091	90.4
1957	9102291	3328097	42245	3370342	90.2
1956	8464867	3117727	31330	3149057	90.3
1955	7698458	2667441	25000	2692441	90.6
1954	6445589	2308536	15550	2324086	91.4
1953	5469483	1982393	0	1982393	90.4
1952	3965256	1501876	0	1501876	84.7
1951	3446259	1407943	0	1407943	102.0
1950	2401275	964882	0	964882	87.7
1949	1680090	670213	0	670213	142.6
1948	114300	39330	0	39330	21.7
1947	74300	37730	0	37730	-

[a]The actual number of pools is somewhat larger since some aggregation of Keg River 'pinnacle reef' pools took place during the gathering of the data.

C.3 Reserve Appreciation

Since the yearly reserve estimates for each pool from its discovery date are too cumbersome to be included here, the data base has been aggregated by producing horizon; this is summarized below in two types of tables. (Tables C.2a through C22.b).

Type 'a' tables contain the annual cumulative reserve estimates for the horizon, as well as a listing of the names of the pools so aggregated. Associated with each such name is a unique nine digit identification code, in which the first three numerals denote the field; the middle three, the geological formation; and the last three, the specific pool within the field.[4]

Ordinarily, the petroleum inventory of a particular region (or geological horizon) can be augmented either through net positive revisions and extensions of existing reserves, or through new discoveries of reserves. The year-by-year changes shown in type 'a' tables reflect a combination of these two effects. Type 'b' tables differentiate between the source of addition more explicitly.

Type 'b' tables indicate how the estimated reserves for discoveries in a particular year appreciate over time (i.e., through extensions and revisions resulting from increased knowledge in the development phase of production).[5] The bottom row of the type 'b' tables shows the cumulative appreciation ratio. For any year n this shows the ratio of the estimate of reserves in pools in that play made n years after discovery to the estimate made of reserves in pools in that play in the discovery year. As can be observed by the leveling off of the cumulative appreciation ratio, the appreciation of these plays is virtually complete.[6] This is not an exhaustive analysis of appreciation, rather it is a convenient and interesting method of presenting the data. It will be noted that, with the exception of the Cardium play, the appreciation in recoverable reserves exceeds the appreciation of oil-in-place. This suggests that 'revisions' (including enhanced recovery schemes) have generally been more important than extensions in pool area. The most obvious weakness of this approach to appreciation is that it focuses only on the number of years following discovery as a factor influencing changes in estimated volumes. One would assume that expected economic conditions in any year also influence the rate of development. This would be especially important for recoverable reserves, since changes in economics and technology can often change the oil recovery factor.

TABLE C.2a

ANNUAL RESERVE ESTIMATES AND MEMBER RESERVOIRS
LEDUC (D-3)

THE TOTAL NUMBER OF POOLS IN THE SPECIFIED RANGE IS 71

THE AGGREGATED RESERVE DATA FOLLOW (MSTD):

YEAR	DIF	RECOVERABLE PRIM	EMH	TOTAL
1976	4553903	2626240	182000	2808240
1975	4540553	2453104	176400	2829504
1974	4575143	2648749	216400	2865149
1973	4575743	2643993	220400	2864393
1972	4542048	2631844	215900	2847744
1971	4504518	2587485	218300	2805785
1970	4461383	2538419	218300	2748719
1969	4439481	2507293	136100	2643393
1968	4429326	2492195	136100	2628295
1967	4412576	2486867	129800	2616667
1966	4407396	2483541	131500	2615041
1965	4336496	2413170	131500	2544670
1964	4292081	2289975	146500	2436375
1963	4333025	2170545	109000	2279545
1962	4318761	2156437	107000	2263437
1961	4272202	2140948	85950	2226898
1960	4245023	2134900	86110	2221010
1959	4066926	2082967	54236	2137203
1958	4037024	2050431	49557	2099988
1957	3866074	2039753	42245	2081998
1956	3670885	1872152	31330	1903482
1955	3867175	1676086	25000	1701086
1954	3939543	1647107	15550	1662657
1953	3889305	1501086	0	1501086
1952	3064100	1262280	0	1262280
1951	2750657	1239949	0	1239949
1950	2222960	910231	0	910231
1949	1666200	666190	0	666190
1948	114000	39300	0	39300
1947	74000	37700	0	37700

Reservoirs

Mnemonic	Pool Code
ACHESON	0097200[illegible]
BASHAW A	0967200[illegible]
BASHAW B	0967200[illegible]
BONNIE GLEN	1517200[illegible]
BUFFALO LK	1767200[illegible]
BUFFALO LK	1767200[illegible]
CLIVE	2247200[illegible]
DUHAMEL A	2967200[illegible]
DUHAMEL B	2967200[illegible]
EAGLES NEST	3157200[illegible]
ERSKINE	3437200[illegible]
EWING LK	3627200[illegible]
FAIRYDELL	3677200[illegible]
FENN BV A	3717200[illegible]
FENN BV B	3717200[illegible]
FENN BV C	3717200[illegible]
FENN BV E	3717200[illegible]
FENN BV F	3717200[illegible]
GLEN PARK	4187200[illegible]
GOLDEN SPK	4217200[illegible]
GOLDEN SPR	4217200[illegible]
GOLDEN SPR	4217200[illegible]
HAYNES	4557200[illegible]
HOMEGLEN-R	4707200[illegible]
INNISFAIL	4947200[illegible]
LEDUC B3A	5217200[illegible]
LEDUC B3B	5217200[illegible]
LEDUC B3C	5217200[illegible]
LEDUC B3D	5217200[illegible]
LEDUC B3E	5217200[illegible]
LEDUC B3F	5217200[illegible]
LITTLE SMK	5457200[illegible]
LOWE FIRE	5747200[illegible]
MALMO B3A	5937200[illegible]
MALMO B3E	5937200[illegible]
PINEVA	6097200[illegible]
MORIN B3A	6267200[illegible]
MORIN B3B	6267200[illegible]
MORIN B3C	6267200[illegible]
NEVIS B3B	6367200[illegible]
NEVIS B3C	6367200[illegible]
NEVIS B3D	6367200[illegible]
NEVIS B3E	6367200[illegible]
NEVIS B3F	6367200[illegible]
NEW NORWAY	6417200[illegible]
NORMANDY A	6547200[illegible]
NORMANDY B	6547200[illegible]
PEWEE B	6947200[illegible]
REDWATER	7727200[illegible]
SIMONETTE	8447200[illegible]
ST ALB B3A	8947200[illegible]
ST ALB B3B	8947200[illegible]
STETTLER A	8667200[illegible]
STETTLER B	8667200[illegible]
STETTLER	8667200[illegible]
STURG LK	8747200[illegible]
STURG LK B	8747200[illegible]
STURG LK B	8747200[illegible]
SYLVAN LK	8917200[illegible]
WEST DRUM	9387200[illegible]
WESTEROSE	9417200[illegible]
WIMBORNE	9767200[illegible]
WINDFALL A	9787200[illegible]
WINDFALL B	9787200[illegible]
WIZ LK A	9857200[illegible]
WIZ LK B	9857200[illegible]
WOSLEE F	9917200[illegible]
YERAU LK A	9967200[illegible]
YERAU LK B	9967200[illegible]
WOOD RIV A	9987200[illegible]
[illegible]	9987200[illegible]

TABLE C.3b

HISTORICAL APPRECIATION OF INITIAL OIL IN PLACE[a] - LEDUC (D-3)

No.[b]	YOD[c]	Years from End of Discovery Year																				
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	1947	74	74	74	202	222	222	336	336	336	336	336	336	307	300	300	300	300	293	293	293	293
2	1948	401	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500
3	1949	401	281	281	281	281	281	281	281	281	281	281	281	281	281	281	281	281	281	281	281	281
4	1950	37	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455
5	1951	300	804	804	804	804	804	804	804	804	804	804	804	804	804	804	804	804	804	804	804	804
6	1952	118	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215
7	1953	11	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
8	1954	60	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
9	1955	187	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210
10	1956	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
11	1957	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
12	1958	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
13	1959	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
14	1960	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
15	1961	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
16	1962	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
17	1963	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
18	1964	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	1965	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
20	1966	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
21	1967	10	10	10	9	9	9	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
22	1968	12	12	10	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
23	1969	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
24	1970	4	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
25	1971	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	1972	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	1973	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	1974	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	1975	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	1976	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative ratio[d]		3.2	3.6	3.9	3.8	4.0	3.9	4.0	3.7	3.7	3.8	3.9	4.0	4.0	4.0	4.0	4.0	4.0	3.9	3.9	4.0	

TABLE C-4b

HISTORICAL APPRECIATION OF TOTAL RECOVERABLE OIL[a] - LEDUC (D-3)

No.[b]	FOR[c]	Years From End of Discovery Year																			
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Cumulative ratio:		2.9	3.6	4.3	4.5	5.0	5.1	5.4	5.3	5.5	5.5	5.8	5.8	6.0	6.2	6.3	6.5	6.5	6.6	6.8	6.8

TABLE C.5a

ANNUAL RESERVE ESTIMATES AND MEMBER RESERVOIRS
NISKU (D-2)

THE TOTAL NUMBER OF POOLS IN THE SPECIFIED RANGE IS 58

THE AGGREGATED RESERVE DATA FOLLOW (MSTB):

YEAR	OIP	RECOVERABLE PRIM	ENH	TOTAL
1976	1281315	559263	66510	625773
1975	1279391	559180	66510	625690
1974	1274401	557117	66410	623527
1973	1271321	555848	54910	610758
1972	1266489	562251	54910	617161
1971	1259469	558546	54910	613456
1970	1268254	563181	70710	633891
1969	1197997	538112	26880	564992
1968	1164526	526905	26880	553785
1967	1126505	493152	28280	521432
1966	1121492	489404	28600	518004
1965	1089158	472772	27200	499972
1964	1069643	422580	27200	449780
1963	1065222	402383	6000	408383
1962	1052304	393641	6000	399641
1961	1033868	394285	0	394285
1960	1034043	396264	0	396264
1959	1051958	388161	0	388161
1958	1038772	385432	0	385432
1957	916483	361124	0	361124
1956	917610	345722	0	345722
1955	889598	254823	0	254823
1954	880461	247582	0	247582
1953	824770	235010	0	235010
1952	691856	177137	0	177137
1951	621902	145964	0	145964
1950	146015	45621	0	45621
1949	11440	3350	0	3350
1948	0	0	0	0
1947	0	0	0	0

Reservoirs

Mnemonic	Pool Code
ACHESON 2B	00969a00[illegible]
ALTA D2	0088a9a00[illegible]
BONNIE G A	15169a0001
ACHESON A	00969a0001
BASHAW A	09669a0001
CHIGWELL A	21469a00[illegible]
CHIGWELL B	21469a0002
CHIGWELL C	21469a0003
CLIVE D2A	22469a0001
CLIVE D2B	22469a0002
CLIVE D2C	22469a0003
DRUMMELLER	29269a0001
DRUM D2B	29269a0002
DUNAMEL A	29869a0001
ERSKINE	34369a0001
EXCELSIOR	34469a0001
EWING LK A	36269a0001
EWING LK B	36269a0002
EWING LK C	36269a0003
EWING LK D	36269a0004
FAIRYDEL A	36769a0001
FAIRYDEL B	36769a0002
FERN BV A	37169a0001
FERN WEST	373a9a0001
GOLDEN SPA	42169a0001
GOLDEN SPB	42169a0002
GLEN PARK	41869a0001
GOOSE RIV	42569a0001
HAYNES	42569a2a01
JOFFRE	50569a0001
LEDUC D2A	55169a0001
LEDUC D2B	55169a0002
LEDUC D2C	55169a0003
LEDUC D2E	55169a0004
LEDUC D2E	55169a0005
LEDUC D2F	55169a0006
LONE PINE	57669a0001
LOUSANA	58169a0001
MALMO D2A	59369a0001
MEEKMAP	60569a0001
MIKWAN	60969a0001
NEW NORWAY	64169a0001
PENHOLD	69469a0001
PADDLE RIV	67269a0001
STETTLER	8aaa9a0001
ST ALBT-BL	8b469a0001
STETTLER S	8b8a9a0001
STURG LK S	87669a0001
SWALWELL A	88669a0001
SWALWELL B	8baa9a0002
WEST DRUM	93669a0001
WIMBORNE A	97669a0001
WIMBORNE B	97669a0002
WIZARD LK	98569a0001
WOOD RIV A	98869a0001
WOOD RIV B	98869a0002
WOOD RIV C	98869a0003
YERAU LK	99469a0001

TABLE C.6b

HISTORICAL APPRECIATION OF INITIAL OIL IN PLACE[a] - NIGERIA (OCT)

R. No.	YOB[c]	Years from End of Discovery Year																			
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	1958																				
	1959																				
	1960																				
	1961																				
	1962																				
	1963																				
	1964																				
	1965																				
	1966																				
	1967																				
	1968																				
	1969																				
	1970																				
	1971																				
	1972																				
	1973																				
	1974																				
	1975																				
	1976																				
Cumulative ratio[d]		1.6	2.7	3.3	3.2	4.8	4.8	4.9	4.9	4.9	4.8	5.0	5.1	5.1	4.9	5.1	5.1	5.1	5.1	5.1	5.1

TABLE C.7b

HISTORICAL APPRECIATION OF TOTAL RECOVERABLE OIL[a] - NISKU (B-2)

No.[b]	YOD[c]	Years From End of Discovery Year																			
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	1947	0	0	0	0	80	57	57	57	57	75	88	88	88	89	69	69	73	92	92	92	92
2	1948	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	1949	3	29	37	39	33	38	34	41	40	40	40	45	65	45	45	45	45	45	48	48	48
4	1950	16	16	53	108	116	127	181	179	180	181	188	202	202	202	215	261	261	261	261	261	261
5	1951	12	14	15	12	11	15	15	16	17	22	20	20	20	23	23	37	37	39	39	44	44
6	1952	14	21	23	24	29	27	27	27	28	28	27	27	34	37	41	41	39	39	42	43	43
7	1953	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1954	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
9	1955	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1956	3	11	33	32	21	22	22	23	22	22	22	22	53	55	75	75	75	75	75	76	76
11	1957	0	0	0	0	0	0	0	0	0	0	0	0	1	1	2	2	2	2	2	2	
12	1958	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		
13	1959	0	1	1	1	1	1	0	1	1	1	0	0	0	0	1	0	0	0			
14	1960	1	1	1	2	2	2	1	1	1	2	2	2	2	2	2	2	2	0			
15	1961	3	6	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7				
16	1962	5	6	5	6	6	6	6	10	10	10	12	12	12	12	12						
17	1963	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0						
18	1964	1	1	1	1	1	1	1	1	1	1	1	1	1	1							
19	1965	0	0	0	0	0	0	0	0	0	0	0	0	0								
20	1966	0	0	0	5	23	18	18	13	25	25	25										
21	1967	0	0	0	2	2	2	2	2	2	2											
22	1968	2	3	4	4	4	4	4	4	4												
23	1969	0	0	0	0	0	0	0	0													
24	1970	0	0	0	0	0	0	0														
25	1971	0	0	0	0	0	0															
26	1972	2	2	2	2	2																
27	1973	1	1	1	0																	
28	1974	0	0	0																		
29	1975	0	0																			
30	1976	0																				
Cumulative ratio:[d]		1.8	3.0	3.9	5.4	5.2	6.0	6.1	6.3	6.7	7.1	7.4	8.1	8.2	8.5	9.6	9.6	10.0	10.1	10.2	10.2	

TABLE C.8a

ANNUAL RESERVE ESTIMATES AND MEMBER RESERVOIRS
VIKING

THE TOTAL NUMBER OF POOLS IN THE SPECIFIED RANGE IS 39

THE AGGREGATED RESERVE DATA FOLLOW (MSTB)

YEAR	DIP	RECOVERABLE PRIM	ENH	TOTAL
1976	1123622	173254	136700	309954
1975	1065012	166519	133700	300219
1974	1027042	157935	132200	290135
1973	951327	152527	130400	282927
1972	853381	145736	123540	269276
1971	805453	142101	119133	261234
1970	778497	139591	108233	247824
1969	750895	138029	81533	219562
1968	641917	132278	62083	194361
1967	468370	104116	54180	158296
1966	375457	99135	28700	127835
1965	365609	93256	28700	121956
1964	361622	92975	28700	121675
1963	348009	91323	24360	115683
1962	343909	91643	20760	112403
1961	332786	89906	20760	110666
1960	300785	85828	20765	106593
1959	325370	80728	8500	89228
1958	401101	95623	7800	103423
1957	427893	101914	0	101914
1956	386438	101924	0	101924
1955	336328	92819	0	92819
1954	278318	79054	0	79054
1953	230700	62297	0	62297
1952	209360	62459	0	62459
1951	73700	22030	0	22030
1950	27300	9030	0	9030
1949	2456	673	0	673
1948	300	30	0	30
1947	300	30	0	30

Reservoirs

Mnemonic	Pool Code
BATTLE	09821000
BATTLE N	10021000
BATTLE S	10121000
BRAZ RIV A	16821000
BRAZ RIV B	16821000
CAROLINE A	19421000
CAROLINE F	19421000
EMIGWELL A	21421000
EMIGWELL B	21421000
CROSSFLD A	24721000
FAIRY BA C	34721000
FERRIER A	37721000
GILBY A	41221000
GILBY B	41221000
GILBY C	41221000
GILBY I	41221000
GILBY E	41221000
GIRDLR LKA	41421000
JOARCAM	50321000
JOFFRE	50521000
JOFFRE S	50721000
JUDY CREEK	50921000
KILLAM A	52421000
KILLAM E	52421000
KIAKPAT A	52621000
LEGAL	55321000
MEL RIV A	60421000
MINN BL A	61221000
OLDS A	66921000
PEAVEY	68321000
PROVOST	75021000
SYLVAN LKA	89121000
SYLVAN LKE	89121000
VIRGINIA H	92521000
WESTWARDHO	94921000
WHITECOURT	95121000
WILLE BA A	96721000
WILLE BA B	96721000
WINTER HLS	98221000

TABLE C.9b

HISTORICAL APPRECIATION OF INITIAL OIL IN PLACE[a] - VIKING

Block No.	FOB[c]	Years from End of Discovery Year																			
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Cumulative ratio[d]		1.0	2.4	4.4	4.7	4.8	4.7	5.2	5.2	5.3	4.7	4.7	4.7	5.1	4.9	5.0	5.1	5.1	5.1	6.3	6.4

TABLE C.10b

HISTORICAL APPRECIATION OF TOTAL RECOVERABLE OIL [a] - VIKING

Yr.	FCC	Years from End of Discovery Year																			
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1967	1967																					
1968	1968																					
1969	1969																					
1970	1970																					
1971	1971																					
1972	1972																					
1973	1973																					
1974	1974																					
1975	1975																					
1976	1976																					
Cumulative ratio:		1.8	3.6	6.4	6.5	7.8	8.0	10.2	10.3	9.5	8.4	9.0	9.0	9.5	9.5	9.7	10.0	10.4	10.5	13.0	13.0

TABLE C.11a

ANNUAL RESERVE ESTIMATES AND MEMBER RESERVOIRS
CARDIUM

THE TOTAL NUMBER OF POOLS IN THE SPECIFIED RANGE IS 59

THE AGGREGATED RESERVE DATA FOLLOW (MSTB):

YEAR	OIP	RECOVERABLE PRIM	ENH	TOTAL
1976	9141452	965750	816330	1782080
1975	9124234	961919	1012430	1974349
1974	9112234	957238	1017050	1974288
1973	9088036	952811	1016720	1969531
1972	9038779	955529	1015040	1970569
1971	8972788	956483	1013430	1969913
1970	8968018	996388	1049130	2045518
1969	8933338	983398	996200	1979598
1968	9029916	973935	935020	1908955
1967	8704094	950249	937920	1888169
1966	8687830	786139	916200	1702339
1965	8436594	744387	836400	1580787
1964	8429103	723012	930000	1653012
1963	5053668	416149	420000	836149
1962	4915653	373336	390000	763336
1961	4528287	721028	299300	1020328
1960	4346170	701235	136000	837235
1959	3937310	650832	121280	772112
1958	2999973	599670	28800	628470
1957	3636909	801459	0	801459
1956	3481997	796812	0	796812
1955	2603977	643506	0	643506
1954	1345887	334586	0	334586
1953	725000	181000	0	181000
1952	0	0	0	0
1951	0	0	0	0
1950	0	0	0	0
1949	0	0	0	0
1948	0	0	0	0
1947	0	0	0	0

Reservoirs

Mnemonic	Pool Code
BONNIE GLN	15117A001
BRAZEAU A	16817A001
CARDIMI A	19417A001
CARDIMI B	19417A002
CARDIMI C	19417A003
CARROT CRK	19617A001
CARROT CRK	19617A002
CARROT CRK	19617A003
CROSSFLD A	24717A001
CROSSFLD B	24717A002
CROSSF E B	24917A002
CROSSF E C	24917A003
CROSSF E D	24917A004
CYN-PEM A	27117A001
CYN-PEM B	27117A002
CYN-PEM C	27117A003
EDSON A	32017A001
EDSON B	32017A002
EDSON C	32017A003
EDSON E	32017A004
FERRIER A	37717A001
FERRIER B	37717A002
FERRIER C	37717A003
FERRIER D	37717A004
FERRIER E	37717A005
FERRIER F	37717A006
FERRIER G	37717A007
FERRIER H	37717A008
FERRIER I	37717A009
FERRIER J	37717A010
GARRING C	40517A003
GARRING AB	40517A00A
GILBY A	41217A001
LANAWAY	54417A001
LANAWAY B	54417A002
LEEDALE A	55217A001
LOCHEAL A	57317A001
MCI RIV A	60417A???
MCI RIV B	60417A002
MINN BL A	61217A001
PECO A	68217A001
PEMBINA	68517A001
PECO B	68217A002
PEMBINA B	68517A002
RICINUS A	78517A001
RICINUS B	78517A002
RICINUS C	78517A003
RICINUS D	78517A004
RICINUS E	78517A005
RICINUS F	78517A006
RICINUS G	78517A007
RICINUS H	78517A008
RICINUS A	78517A???
RICINUS I	78517A???
RICINUS M	78517A???
RICINUS O	78517A???
RICINUS G	78517A???
SYLVAN LKA	89117A???
WILLESDEN	96717A???

TABLE C.12b

HISTORICAL APPRECIATION OF INITIAL OIL IN PLACE[a] - CARBIUM

No.[b]	YOD[c]	Years From End of Discovery Year																			
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	1953	725	1340	2550	3400	3550	2880	3790	4000	4100	4300	4300	7690	7650	7670	7670	7720	7440	7440	7440	7440	7440
2	1954	0	52	79	84	117	143	249	295	431	496	470	488	706	718	739	857	857	858	884	884	884
1	1955	2	2	2	2	2	2	3	3	7	7	7	7	7	11	25	25	25	25	25	25	25
1	1956	1	1	5	5	82	111	161	161	161	161	161	163	162	162	162	162	163	164	164	164	164
0	1957	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
1	1958	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	1		
0	1959	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
5	1960	13	13	13	13	13	13	13	13	13	13	13	13	13	14	14	15	15				
5	1961	7	7	7	8	11	11	11	11	12	12	12	12	12	12	12	12					
2	1962	2	50	50	50	40	40	40	40	40	40	40	40	40	40	40						
7	1963	21	29	47	52	52	52	147	161	161	161	161	161	114	114							
1	1964	1	1	2	2	2	2	2	2	2	3	3	3	3								
3	1965	9	19	19	171	171	171	171	171	171	171	194	194									
7	1966	9	9	10	10	10	10	17	17	17	18	18										
1	1967	1	1	3	3	3	3	3	24	24	24											
1	1968	0	0	0	1	1	1	1	1	2												
8	1969	50	67	67	67	68	68	102	127													
2	1970	3	3	21	41	41	41	41														
3	1971	4	4	4	4	4	5															
3	1972	13	31	31	31	31																
6	1973	8	12	12	12																	
0	1974	0	0	0																		
0	1975	0	0																			
0	1976	0																				
Cumulative ratio:[d]		1.9	3.3	4.5	4.8	4.2	5.5	5.9	6.2	6.5	6.5	10.6	10.8	10.8	10.9	11.1	10.7	10.7	10.8	10.8	10.8	

TABLE C.13b

HISTORICAL APPRECIATION OF TOTAL RECOVERABLE OIL[a] - CARDIUM

No.[b]	YOD[c]	Years From End of Discovery Year																			
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	1953	181	334	638	788	792	616	758	800	986	710	770	1588	1502	1560	1717	1706	1731	1773	1691	1692	1692
2	1954	1	5	8	9	12	14	24	24	35	40	38	48	103	123	134	156	166	171	171	171	171
2	1955	0	0	0	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	1	1	1
0	1957	0	0	0	0	12	11	16	16	16	16	16	24	24	24	24	24	18	18	18	18	18
1	1958	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
0	1959	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
3	1960	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1				
5	1961	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1					
2	1962	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1						
7	1963	2	6	6	6	13	13	14	14	14	14	14	14	14	14							
1	1964	0	0	0	0	0	0	0	0	0	0	0	0	0								
5	1965	1	1	1	1	14	27	33	33	32	32	31	31									
1	1966	1	1	1	1	1	1	2	2	2	2	2										
1	1967	0	0	0	0	0	0	0	1	1	1											
8	1968	0	0	0	0	10	10	16	20	0												
2	1969	0	0	0	0	0	0	0	0													
3	1970	0	0	0	0	4	4	4														
3	1971	0	0	0	0	0	0															
6	1972	1	3	3	3	3																
0	1973	1	1	1	1																	
0	1974	0	0	0																		
0	1975	0	0																			
0	1976	0																				
Cumulative ratio:[d]		1.8	3.4	4.3	4.5	3.7	4.5	4.8	5.8	4.4	4.7	9.1	8.9	9.3	10.2	10.3	10.4	10.7	10.3	10.3	10.3	

TABLE 14a

ANNUAL RESERVE ESTIMATES AND MEMBER RESERVOIRS
GRANITE WASH

THE TOTAL NUMBER OF POOLS IN THE SPECIFIED RANGE IS 15

THE AGGREGATED RESERVE DATA FOLLOW (MSTB):

YEAR	OIP	RECOVERABLE PRIM	ENH	TOTAL
1976	160890	42841	0	42841
1975	160890	42841	0	42841
1974	163890	41533	0	41533
1973	163890	41872	0	41872
1972	161120	42410	0	42410
1971	161120	42389	0	42389
1970	161120	42389	0	42389
1969	158843	42553	0	42553
1968	155203	41460	0	41460
1967	148783	38596	0	38596
1966	103161	29071	0	29071
1965	87615	16609	0	16609
1964	49018	9395	0	9395
1963	25016	5176	0	5176
1962	22907	4869	0	4869
1961	22907	4869	0	4869
1960	31707	6893	0	6893
1959	33107	7215	0	7215
1958	27007	5401	0	5401
1957	4557	910	0	910
1956	4557	910	0	910
1955	0	0	0	0
1954	0	0	0	0
1953	0	0	0	0
1952	0	0	0	0
1951	0	0	0	0
1950	0	0	0	0
1949	0	0	0	0
1948	0	0	0	0
1947	0	0	0	0

Reservoirs

Mnemonic	Pool Code
Loon	579976001
Lubicon	587976001
Red Earth A	764976001
Red Earth B	764976002
Red Earth C	764976003
Red Earth D	764976004
Red Earth E	764976005
Red Earth F	764976006
Red Earth I	764976009
Red Earth J	764976010
Red Earth K	764976011
Red Earth L	764976012
Red Earth M	764976013
Red Earth N	764976014
Red Earth O	764976015

TABLE C.15b

HISTORICAL APPRECIATION OF INITIAL OIL IN PLACE[a] - GRANITE WASH

No.[b]	YDB[c]	Years From End of Discovery Year																			
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	1950	5	5	5	5	5	5	5	5	5	10	21	21	21	21	21	21	21	21	21	15	15
2	1957	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	1958	22	28	26	18	18	18	41	59	69	89	89	89	90	90	90	90	90	93	93		
4	1959	1	0	1	1	1	1	1	1	25	28	28	28	28	28	28	28	90	28			
5	1960	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
6	1961	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
7	1962	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0						
8	1963	0	0	0	0	0	0	0	0	0	0	0	0	0	0							
9	1964	1	0	0	0	0	0	0	0	0	0	0	0	0								
10	1965	10	10	10	10	10	10	10	10	10	10	10	10									
11	1966	0	0	0	0	0	0	0	0	0	0	0										
12	1967	1	0	0	0	0	0	0	0	0	0											
13	1968	2	4	4	4	4	4	4	4	4												
14	1969	0	0	0	0	0	0	0	0													
15	1970	0	0	0	0	0	0	0														
16	1971	0	0	0	0	0	0															
17	1972	0	0	0	0	0																
18	1973	0	0	0	0																	
19	1974	0	0	0																		
20	1975	0	0																			
21	1976	0																				
Cumulative ratio:[d]		1.4	1.4	1.2	1.2	1.2	1.8	2.2	3.0	3.8	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.1	4.1	2.9	2.9	

TABLE C.10b

HISTORICAL APPRECIATION OF TOTAL RECOVERABLE OIL[a] - GRANITE WASH

No.[b]	YOD[c]	Years from End of Discovery Year																			
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	1956	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	1957	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
3	1958	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		
4	1959	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			
5	1960	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1				
6	1961	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1					
7	1962	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1						
8	1963	1	1	1	1	1	1	1	1	1	1	1	1	1	1							
9	1964	1	1	1	1	1	1	1	1	1	1	1	1	1								
10	1965	1	1	1	1	1	1	1	1	1	1	1	1									
11	1966	1	1	1	1	1	1	1	1	1	1	1										
12	1967	1	1	1	1	1	1	1	1	1	1											
13	1968	1	1	1	1	1	1	1	1	1												
14	1969	1	1	1	1	1	1	1	1													
15	1970	1	1	1	1	1	1	1														
16	1971	1	1	1	1	1	1															
17	1972	1	1	1	1	1																
18	1973	1	1	1	1																	
19	1974	1	1	1																		
20	1975	1	1																			
21	1976	1																				
Cumulative ratio:[d]		1.4	1.4	1.1	1.1	1.0	1.2	2.3	4.3	5.4	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	6.3	6.3	5.3	5.3

TABLE C.17a

ANNUAL RESERVE ESTIMATES AND MEMBER RESERVOIRS
BEAVERHILL LAKE

THE TOTAL NUMBER OF POOLS IN THE SPECIFIED AREA IS 2.

THE AGGREGATED RESERVE DATA FOLLOW [illegible]

YEAR	D.F.	RECOVERABLE PRIM.	RECOVERABLE Sec.	RECOVERABLE TOTAL
19[illegible]	[illegible]	1000824	1663301	2664125
1975	[illegible]	994095	1662001	2656096
1976	[illegible]	990668	1662001	2652669
1977	[illegible]	974368	1662001	2636369
1978	[illegible]	970168	1513701	2483869
1979	[illegible]	932849	1507001	2439850
1980	[illegible]	920303	1494656	2414959
1981	[illegible]	823916	1492256	2316172
1982	[illegible]	821316	1469756	2291072
1983	[illegible]	816080	1372556	2188636
1984	[illegible]	796419	1360006	2156425
1985	[illegible]	917063	1219506	2136569
1986	[illegible]	1045576	1141902	2187478
1987	[illegible]	938515	1[illegible]	[illegible]
1988	[illegible]	[illegible]	0	[illegible]
1989	[illegible]	[illegible]	0	[illegible]
1990	[illegible]	[illegible]	0	[illegible]
1991	[illegible]	[illegible]	0	[illegible]
1992	[illegible]	[illegible]	0	[illegible]
1993	[illegible]	[illegible]	0	[illegible]
1994	[illegible]	[illegible]	0	[illegible]
1995	0	0	0	0
1996	0	0	0	0
1997	0	0	0	0
1998	0	0	0	0
1999	0	0	0	0
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0

Reservoirs

Mnemonic	Pool Code
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]

TABLE C.18b

HISTORICAL APPRECIATION OF INITIAL OIL IN PLACE[a] - BEAVERHILL LAKE

No.	Year[b]	Years from End of Discovery Year[c]																	
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
1	1957	251	825	1529	2303	2740	3118	3220	3320	3140	2690	2690	2660	2660	2660	2660	2660	2660	2660	2660	2689
2	1958	1450	1753	1943	2051	2180	2300	2370	2382	2307	2600	2350	2315	2315	2315	2315	2315	2315	2315	2315	265
3	1959	4500	1740	2460	2480	2480	2480	2480	2480	2480	2480	2480	2480	2480	2480	2480	2480	2480	2480	2480	2480
4	1960		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
5	1961		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
6	1962		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
7	1963		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
8	1964		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
9	1965		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
10	1966		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
11	1967		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
12	1968		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
13	1969		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
14	1970		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
15	1971		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
16	1972		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
17	1973		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
18	1974		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
19	1975		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
20	1976		1750	1940	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110	2110
Cumulative ratio:		2.9	3.6	4.5	4.5	5.0	5.1	5.4	5.3	5.5	5.5	5.8	5.8	6.0	6.2	6.3	6.3	6.5	6.6	6.8	

TABLE C.19b

HISTORICAL APPRECIATION OF TOTAL RECOVERABLE OIL[a] - BEAVERHILL LAKE

No.[b]	YOD[c]	Years from End of Discovery Year																		
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
3	1957	23	183	298	411	497	527	541	1317	966	1035	1066	1090	1090	1090	1090	1091	1093	1103	1105	1117
1	1958	0	1	11	25	31	30	84	82	84	84	84	109	110	120	128	115	115	124	124	
5	1959	90	254	290	536	491	752	974	1042	923	955	955	958	964	1108	1098	1255	1262	1257		
2	1960	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
5	1961	2	3	3	2	3	3	3	3	3	3	3	3	3	3	3	4				
1	1962	0	20	24	82	82	82	87	87	87	87	87	87	87	88	88					
1	1963	2	26	26	27	26	70	70	70	72	72	72	72	72	72						
1	1964	2	2	0	0	0	0	0	0	0	0	0	0	0							
2	1965	1	1	1	1	1	1	1	5	0	0	0	3								
0	1966	0	0	0	0	0	0	0	0	0	0	0									
0	1967	0	0	0	0	0	0	0	0	0	0										
0	1968	0	0	0	0	0	0	0	0	0											
0	1969	0	0	0	0	0	0	0	0												
0	1970	0	0	0	0	0	0	0													
0	1971	0	1	0	1	0	0														
0	1972	1	0	0	0	0															
0	1973	0	0	0	0																
0	1974	0	0	0																	
0	1975	0	0																		
0	1976	0																			
Cumulative ratio:[d]		3.4	4.8	6.2	7.0	8.0	8.2	8.7	8.2	7.6	7.6	7.6	7.6	7.7	7.7	7.8	7.8	7.8	7.8	7.8	

TABLE C.20a

ANNUAL RESERVE ESTIMATES AND MEMBER RESERVOIRS
KEG RIVER

THE TOTAL NUMBER OF POOLS IN THE SPECIFIED RANGE IS 121

THE AGGREGATED RESERVE DATA FOLLOW (MSTB):

YEAR	OIP	RECOVERABLE PRIM	RECOVERABLE ENH	RECOVERABLE TOTAL
1974	3525341	1099326	504811	1604137
1975	3527011	1101123	503143	1604266
1974	3551681	1129339	486811	1616150
1973	3542980	1140661	474466	1615127
1972	3529166	1195352	465149	1660501
1971	3485697	1236397	430864	1667261
1970	3587403	1164237	467485	1631722
1969	4073249	1313730	438785	1752515
1968	3990033	1332951	190200	1523151
1967	3328014	1142115	159000	1301105
1966	2121270	608251	159000	867251
1965	1706607	873154	159000	432174
1964	389300	57807	159000	216807
1963	1300	207	0	207
1962	1300	207	0	207
1961	1300	207	0	207
1960	1300	207	0	207
1959	1300	207	0	207
1958	1300	207	0	207
1957	1300	207	0	207
1956	1300	207	0	207
1955	1300	207	0	207
1954	1300	207	0	207
1953	0	0	0	0
1952	0	0	0	0
1951	0	0	0	0
1950	0	0	0	0
1949	0	0	0	0
1948	0	0	0	0
1947	0	0	0	0

Reservoirs Mnemonic	Pool Code
AMOEBA A-G	052788001
AMOEBA H	052788008
AMOEBA I	052788009
AMOEBA J	052788010
BLACK A	144788001
BLACK B	144788002
FIRE A	381788001
FIRE B	381788002
FIRE C	381788003
LAKE A	945788001
LAKE B	945788002
LAKE C	945788003
LAKE D	945788004
LAKE E	945788005
LAKE F	945788006
LAKE G	945788007
LAKE H	945788008
LAKE I	945788009
LAKE J	945788010
LAKE K	945788011
LAKE L	945788012
LAKE M	945788013
LAKE N	945788014
LAKE O	945788015
LAKE P	945788016
LAKE Q	945788017
LAKE R	945788018
RAINBOW A	753788001
RAINBOW B	753788002
ZAMA F4F	997788231
ZM 842-84F	997788233
ZM 845-747	997788245
ZAMA I4I	997788252
ZAMA M5A	997788301
ZAMA P5P	997788302
ZM P3I-M3M	997788204
ZAMA I3I	997788209
ZM J3J-L3L	997788210
ZAMA M3M	997788213
ZAMA N3A	997788214
ZAMA O3O	997788215
ZAMA P3P	997788216
ZM O3O-C4C	997788217
ZAMA B4B	997788230
ZAMA E4E	997788231
VR I2I-B2B	926799135
VR T2T-W2W	926799140
VR K2K-B3B	926799150
VR C3C-B3B	926798203
VIRGO M3M	926799209
ZAMA A-WWW	997788001
ZM WWW-Z2Z	997788123
ZAMA A3A	997788201
ZAMA B3B	997788202
ZAMA C3C	997788203
VIRGO A	926798001
VIRGO B	926798002
VIRGO C	926798003
VIRGO D	926798004
VIRGO E	926798005
VIRGO F-GG	926798006
VIRG PP-ZZ	926798062
VIRGO AAA	926798101
VR BBB-M3M	926798102

Reservoirs Mnemonic	Pool Code
RAINBW B-D	753788004
RAINBOW F	753788006
RAINBOW R	753788016
RAINBOW S	753788019
RAINBOW T	753788021
RAINBOW U	753788022
RAINBOW V	753788023
RAINBOW W	753788024
RAINBOW X	753788025
RAINBOW Y	753788026
RAINB Z-FF	753788033
RAINBOW GG	753788034
RAIN HH-OO	753788042
RAIN PP-SS	753788044
RAINBOW TT	753788046
RAINBOW UU	753788047
RBW VV-GGG	753788048
RAINBW HHH	753788106
RB III-MMM	753788109
RAINBW OOO	753788115
RAINBW QQQ	753788117
RAINBW RRR	753788118
RAINBW SSS	753788119
RAINBW TTT	753788120
RAINBW S A	754788001
RAINBW S B	754788002
RAINBW S C	754788003
RAINBW S D	754788004
RAINBW S E	754788005
RAINBW S F	754788006
RAINBW S G	754788007
RAINBW S H	754788008
RAINBW S I	754788009
RAINBW S J	754788010
RAINBW S K	754788011
RAINBW S L	754788012
RAINBW S M	754788013
GENEX	835788001
SHEKILIE A	835788001
SHEKILIE B	835788002
SHEKILIE C	835788003
SHEKILIE D	835788004
SHEKILIE E	835788005
SHEKILIE F	835788006
SOUSA A	858788001
SOUSA B	858788002
SOUSA C	858788003
SOUSA D	858788004
SOUSA E J	858788005
YEMZE A	900788001
ANTE CH A	985788001
BILWOOD A	812788001
MITSUE A	815788001
MITSUE C	815788003
NIPISI A	644788001
NIPISI C	644788003
UTIKUM LKA	917788001
UTIKUM LKB	917788002

TABLE C.21b

HISTORICAL APPRECIATION OF INITIAL OIL IN PLACE[a] - KEG RIVER

No.[b]	YOD[c]	Years from End of Discovery Year																			
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	1954		1	1	1	1	1	1	1	1	1	1	1	3	3	3	3	3	3	3	3	3
10	1955		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	1956		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	1957		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	1958		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	1959		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	1960		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	1961		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	1962		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	1963		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1964		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	1965	288	671	731	731	807	811	811	811	811	811	811	811	811	0	0	0	0	0	0	0	0
11	1966	1014	1059	1138	1103	1086	1088	1097	1097	1097	1097	1097	1097	0	0	0	0	0	0	0	0	0
21	1967	328	536	525	527	527	504	504	504	510	510	510	0	0	0	0	0	0	0	0	0	0
25	1968	920	727	601	554	525	521	504	504	492	499	0	0	0	0	0	0	0	0	0	0	0
24	1969	228	380	505	286	257	256	254	254	254	0	0	0	0	0	0	0	0	0	0	0	0
6	1970	662	211	109	203	203	200	195	197	0	0	0	0	0	0	0	0	0	0	0	0	0
13	1971	85	53	53	48	48	48	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	1972	207	76	64	64	57	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	1973	105	43	43	35	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1974	32	17	17	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1975	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	1976	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative ratio:[d]		0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.3	1.3	1.3	0.8	0.8	0.8	0.8

TABLE C.22b

HISTORICAL APPRECIATION OF TOTAL RECOVERABLE OIL[a] - KEG RIVER

No.[b]	Yr[c]	Years from End of Discovery Year																			
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	1954	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	1955	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
0	1956	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
0	1957	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
0	1958	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
0	1959	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
0	1960	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0						
0	1961	0	0	0	0	0	0	0	0	0	0	0	0	0	0							
0	1962	0	0	0	0	0	0	0	0	0	0	0	0	0								
0	1963	0	0	0	0	0	0	0	0	0	0	0	0									
0	1964	0	0	0	0	0	0	0	0	0	0	0										
1	1965	217	0	0	0	0	0	0	0	0	0	0										
1	1966	1149	931	0	0	0	0	0	0	0	0											
1	1967	3197	2588	1111	0	0	0	0	0	0												
2	1968	2067	1673	718	327	0	0	0	0													
2	1969	2064	1671	717	327	140	0	0	0													
2	1970	226	183	78	36	15	7	0														
1	1971	71	57	24	11	5	2	1														
0	1972	31	25	11	5	2	1															
0	1973	0	0	0	0	0	0															
1	1974	1	1	0	0	0																
1	1975	1	1	0	0																	
0	1976	0	0	0																		
Cumulative ratio[d]		1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

[a] Rounded to nearest 10^6 stb.

[b] Number of separate reservoirs discovered in the indicated year.

[c] Year of discovery.

[d] This 'cumulative appreciation ratio' is calculated by first dividing the sum of the nth column by the sum of the (n-1)th column (excluding its last entry); and then by multiplying that result by the previous (n-1) appreciation ratio.

The analysis in Chapter 3 and Appendix B of this study was based on the 1976 estimates of oil-in-place and reserves. As is noted in the text, this raises the possibility of bias in the results, since the more recent discoveries have not had the same time to undergo appreciation as have the earlier finds; were allowances made for appreciation, the estimated decline in average discovery size (with depletion of the play) might be significantly less. The appreciation tables for the various plays suggest that any such bias is likely to be small, if only because there have been relatively few discoveries in most plays in the 1970s.

Table C.23 includes data on appreciation in the seven main oil plays, and permits several conclusions. (1) In most of the plays a relatively small proportion of pools were found after 1966 (Keg River and Cardium are the main exceptions). Thus, the data for most includes at least ten years' appreciation. (2) In all plays except the Keg River, the most recent recorded discovery has at least three years' appreciation of reserves. It can be seen from the appreciation tables that in most plays the first two or three years account for the most rapid appreciation in reserves. (3) Volume estimates for pools discovered after 1966 appreciated much less in the first several years, than they did for pools found before 1966. This suggests that appreciation is a less significant factor for the more recent finds. (If the appreciation largely reflects areal extension of the pool with development, it is of interest to note that the rise in oil prices in the early 1970s and relaxation of market demand restrictions could be expected to offer incentives to develop pools quickly. It should be remarked that other factors, such as closeness to transmission facilities, are also important; as well, even were demand relatively low compared to productive capacity, as in the 1950s and early 1960s, the prorationing regulations themselves offered encouragement to development drilling. (4) The average discovery size of pools since 1966 has generally been very small compared to the average in the play as a whole. Clearly smaller pools require less drilling to determine the extent of oil volumes. This can be seen most clearly in the case of the Keg River pools where there has been no appreciation, on average.

Slightly more detailed discussion of the information in Table C.23 may be of value. The first two columns show the number of years before the cumulative appreciation ratio reached 80 percent of the total value attained for that play. (Values were calculated for 20 years of appreciation where sufficient data was available--i.e., in pools discovered before 1957.) These values suggest that in most plays

TABLE C.23

APPRECIATION IN RECENT DISCOVERIES BY PLAY

Plays	No. of Years Before Appreciation Attains 80 percent		Proportion of Pools With < Ten Yrs. Appreciation	N Yrs. of Appreciation for Last Discovery	Ratio of Avg. Discovery Size 1967-76 to Average Discovery Size Before 1967[d]		Ratio of Final Appreciation Factor[b] to N Year Appreciation Factor		Ratio of Estimated O-in-P[e] After N Years to Estimated O-in-P in Discovery Year			Ratio of Estimated Recoverable Oil After N Years to Estimated Recoverable Oil in Discovery Year		
	Oil-In-Place	Recoverable Oil			Oil-In Place	Recoverable	Oil-In Place	Recoverable	Last Find	Finds 1967-1976	Finds Before 1976	Last Find	Finds 1967-1976	Finds Before 1976
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Leduc	1	9	.18	4	.04	.03	1.05	1.5	1.5	0.8	3.9	1.0	0.9	4.2
Nisku	4	12	.12	3	.31	.23	1.50	2.6	1.0	1.8	3.5	0	1.6	4.1
Viking	16	7	.25	3	.25	.08	1.50	1.6	3.0	1.2	6.1	*	3.0	7.9
Cardium I[a]	11	11	.53	3	.04	.02	2.40	2.4	1.5	2.0	4.4	1.0	2.0	4.8
Cardium II[a]	12	14	.53	3	.36	.53	3.80	7.1	1.5	2.0	5.6	1.0	2.0	5.0
Granite Wash	8	8	.33	3	.86	.29	2.40	4.8	1.0	2.7	0.9	*	1.0	1.2
Beaverhill Lake	9	4	.05	5	.02	.00	1.40	1.0	1.0	1.0	8.6	*	*	12.1
Keg River[c]	0	0	N/A	2	N/A	N/A	1.00	1.0	1.0	0.4	1.5	*	0.5	1.9

NOTES: *Year of discovery estimate less than 500,000 barrels.

[a]Cardium II excludes the Pembina pool.
[b]20-year factor except for Beaverhill Lake year (19) and Keg River (12 year).
[c]The data aggregated some pools in the Keg River play.
[d]Evaluated after N years.
[e]Oil-In-Place.

the majority of the appreciation was completed in about ten years. Column three shows the proportion of oil pools in the play discovered in the last ten years under consideration: in the Beaverhill Lake, Nisku and Leduc plays less than one-fifth of the pools examined include less than 10 years appreciation. Column four calculates a variable which is labelled "N" in the remainder of the table: it is the number of years' appreciation for the most recent pool found in that play included in the data base. It can be seen that, except for the Keg River play, all pools include at least three years' appreciation. Columns five and six show the ratio of the estimated size of pools discovered in the last ten years to the estimated size of pools discovered prior to that; pool size has been based on the estimate N years after discovery, so that lack of sufficient time for appreciation does not unduly reduce the ratio. It can be seen that in the Leduc, Cardium, and Beaverhill Lake plays, the more recent pools are less than 5 percent the size of the earlier finds. Therefore, one would expect less appreciation over time due to areal development of the pool; also the smaller size might make variations in reservoir characteristics within the pool less pronounced, so that surprises in recovery are less likely. As a result, underestimate of pool volumes in the more recent finds in these plays, because of insufficient time for appreciation, seems unlikely. (It must be noted that the ratio for the Cardium play is very much affected by the large size of Pembina.) Columns seven and eight show, for all pools in the play, the ratio of the final cumulative appreciation ratio to that after N years. It can be seen that there is, on average, no appreciation of reserve estimates after N years in the Keg River play. In the Leduc, Viking and Beaverhill Lake plays, less than 60 percent appreciation still remains on average, after N years. This is relatively small considering that total appreciation generally runs from 500 to 1,000 percent. In the Cardium, Granite Wash and Nisku (for recoverable reserves) plays, it seems that underestimation may be somewhat more significant. Finally, columns nine through fourteen compare the appreciation ratios over the first N years for discoveries in the period 1967-1976, with that for pools found before 1967. It can be seen that the pools found more recently on average showed much less appreciation over the first N years than pools found before 1967.

In conclusion, it would appear that little bias is imparted to the analysis by the use of the 1976 reserve data (with no allowance for subsequent appreciation of the more recent finds); in fact, the use of average appreciation factors for the play to increase the 1976 reserve estimates for the recent smaller discoveries would seem likely to

over-state the volumes of oil. Certainly in the Leduc, Beaverhill Lake and Keg River plays this conclusion seems fully warranted. In the Leduc and Beaverhill Lake, the finds since 1967 were very small, and showed no appreciation at all on average over the first three or four years, unlike the larger pools discovered earlier. In the Keg River play virtually all single pools are relatively small, and even those found in the mid-1960s showed little appreciation to 1976. The Viking play is similar to the Leduc insofar as appreciation is concerned, although recent finds have been relatively larger (i.e., compared to the average find in the play). Moreover, in all these plays, very little reserve appreciation on average occurred after three or four years, even for the earlier finds.

The issue is less clear for the Nisku, Granite Wash and Cardium formations. In these plays there have been relatively more finds since 1967, the average size of the new discoveries has been closer to the average for the entire history of the play (if Pembina is excluded from the Cardium), and the 1976 reserves estimated for the average pool exceeded the estimate three years after discovery by more than in the plays previously discussed. On the other hand, pools discovered after 1967 showed significantly less appreciation in the first three years than did older pools. On balance, then, it would appear that there is some understatement of the size of more recent discoveries in the Cardium, Nisku and Viking plays, but that use of the average pool appreciation factor for 20 years would overstate ultimate recovery in these pools.

Footnotes

[1]The physical descriptions and distribution of the seven formations are drawn from the Lexicon of Geologic names in the Western Canada Sedimentary Basin and Arctic Archipelago (Calgary: ASPG, 1960). For some formations a 'type well' is given. In such a well a typical stratigraphic section for the formation may be identified.

[2]Energy Resources Conservation Board, Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur, Annual Publication No. 18.

[3]Because of similar physical characteristics and discovery years, a great many of the small reservoirs in the Rainbow-Zama fields (Keg River formation) were grouped together from a total of about 410 individual annual pool reserve estimates. George Isherwood assembled the majority of the historical reserves data for us.

[4]Over 400 distinct geological classifications are utilized, giving an indication of the rigor involved in the designation of the producing horizon. The identification codes are those of the Energy Resources Conservation Board.

[5]Prior to 1976, the Energy Resources Conservation Board presented appreciation statistics for the aggregate provincial reserve estimates. Besides a tabular and graphical display, these consisted of a textual analysis (for instance, see Section V, "Trends in Reserves," OGCB Report 70-18).

[6]The cumulative appreciation ratio is an average of many discovery year groups and, as such, should be interpreted cautiously. The pattern of growth for any particular discovery year can be significantly different from the average. This degree of variation is due in part to the nature of the pools themselves, but also reflects the vagaries of timing of their discovery, especially where discovery occurred at the beginning or end of the year. J. Wiorkowski ("Estimating Volumes of Remaining Fossil Fuel Resources: A Critical Review," Journal of the American Statistical Association, 1981, pp. 543-559) notes that there are a number of different ways of calculating average appreciation ratios. He finds significantly different results for the U.S. between the method used here (appreciation of aggregated reserves across different pools) and a method averaging the separate appreciation ratios for different pools. The method of calculating appreciation ratios used here is the same as that used by the ERCB in its various reserves reports. C. Van de Panne noted that somewhat different results are obtained if a more formal curve fitting technique is utilized. C Van de Panne, "The Development of Oil and Gas Reserves in Alberta," Discussion Paper 15, Department of Economics, University of Calgary, 1971.

[7]J. G. Gray, and F. L. Fournier, "Developments in Canada in 1947," Bulletin of the AAPG 32 (1948):1080.

[8]H. G. Gammell, "The Viking Member in Central Alberta," Journal of the ASPG 3 (May 1955):63.

[9]H. E. Parsons, "Developments in Western Canada in 1953," Bulletin of the AAPG 38 (1954):1281.

[10]J. C. Sproule, "The Granite Wash of Northern Alberta," Journal of the ASPG 4 (October 1956):213.

[11]W. A. Hiles, and G. J. McMurtry, "Developments in Western Canada in 1957," Bulletin of the AAPG 42 (1958):1417.

[12]T. J. Latus, "Developments in Western Canada in 1965," Bulletin of the AAPG 50 (1966):1287.

APPENDIX D

MEASURES OF EXPLORATORY ACTIVITY IN ALBERTA

Appendix D

MEASURES OF EXPLORATORY ACTIVITY IN ALBERTA

In this appendix a detailed summary is presented of the level of exploratory effort in Alberta. The data are disaggregated by year and geographical area. Figure D.1 illustrates the geographical units of investigation.[1]

D.1 Nature of the Data Base

The underlying data base is the ERCB's 'General Well Data File'. Regulations require that detailed drilling information be provided by the operators involved. This in turn is transcribed onto the computer and available to the public after any confidentiality limits have elapsed. Depending on the extent of its activity, each well ever drilled inside provincial boundaries could be represented by as many as twelve separate types of fixed length records within that file.

The initial step in deriving a measure of exploratory effort was one of extracting the relevant portions of data from this vast accumulation. We proceeded by specifying two binding constraints pertaining to the nature of the data to be retrieved: the first concerning the type of well, and the second relating to the amount of information required for each well so chosen.

- Only data pertaining to 'exploratory wells' were elicited.
- Two specific types of records were deemed sufficient; these were the 'Basic Well Data' and the 'Geological Tops and Markers' records.

Although there do exist differing views as to what exactly constitutes an exploratory well, the conventional wisdom of the Lahee classification system will be adhered to in this study (excluding outpost, or step-out, wells).[2] Under the heading of exploratory drilling Lahee lists these classes of wells--'wildcat wells' (this includes new-field and new-pool wildcats), 'deeper-pool tests', and 'shallow-pool tests'. A wildcat well is defined as one that is located a considerable distance outside the limits (as perceived at the time) of producing pools. The differentiation between new-field and new-pool

Figure D.1: Map of Alberta Showing ERCB Area Codes

wildcats is based on the risk involved. A new-field wildcat is a hole drilled in a geological environment where petroleum has not yet been discovered. A new-pool wildcat, on the other hand, is directed towards zones where other pools have been found, but where the underground complexities are such that searching for a new pool is very hazardous. A deeper-pool test is a well located within the known limits of a pool and drilled with the objective of finding new producible formations below that attributed to the pool in question. A shallow-pool test is similar, but, as its name suggests, new commercial horizons above those known are its goal.

So, in our data base, for each well falling within one of these selected exploratory classifications there always exists one 'Basic Well Data' record, and if actual drilling commenced (as opposed to mere licensing) one or more (depending on the number of horizons penetrated) of the 'Geological Tops and Markers' records. These specifications resulted in 20,255 of the former, and 22,835 of the latter type of records being extracted from the ERCB computer and utilized for this study.[3]

The 'Basic Well Data' record contains such information as: geographical location (this being in the form of a unique well identifier by which all records are sequenced), well name, the assigned field/pool code (if it happened to be successful), the spud date, total depth, and the current well status. The 'Geological Tops and Markers' record, in addition to the geographical identifier, is comprised of the formations encountered (through the use of formation codes coinciding to those utilized with respect to the reserve data), and at which depths.

D.2 A Tabular Summary of Exploratory Effort

The following tables are of two general types. The first (Tables D.1 - D.5) deal with exploratory wells--number drilled, average depth, and number successful; while the latter (Tables D.6 - D.14) present an alternative measure of exploratory activity--penetrations by geological horizon, both number and average depth of occurrence. Numbers are given for each of the 29 Alberta regions shown in Figure D.1.

Note that observations for 194' and all previous years are lumped together in the entry presented for 194'.

TABLE D.1

NEW FIELD WILDCATS - NUMBER

TABLE D.2

ALL EXPLORATORY WELLS - NUMBER

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1967	128	55	61	93	0	17	0	110	10	1	139	14	8	3	9	12	7	8	1	2	0	1	5	2	0	1	12	6	687
1968	0	9	8	39	1	2	0	6	4	2	4	0	0	3	7	11	20	2	1	7	0	0	0	1	0	1	1	0	132
1969	7	8	19	38	7	7	0	7	5	6	1	0	0	0	8	30	29	20	0	9	0	0	0	4	1	1	3	0	205
1970	3	12	9	13	2	4	0	3	3	11	0	0	0	24	17	23	17	9	0	0	0	1	0	3	1	2	20	2	189
1971	31	39	22	19	1	4	0	13	10	23	4	2	3	19	28	47	24	14	0	7	0	1	0	5	0	7	38	19	379
1972	24	34	30	42	25	9	0	18	20	16	2	2	3	26	49	54	17	10	3	6	0	2	1	3	1	4	39	3	442
1973	33	24	39	24	12	1	0	10	22	20	2	5	9	19	20	21	12	9	3	6	1	2	0	4	1	0	14	6	327
1974	26	28	49	12	3	0	0	11	34	13	7	3	10	20	10	14	10	1	9	7	5	23	3	3	0	29	16	6	364
1975	31	20	21	9	0	0	0	14	32	9	10	10	13	31	8	15	16	12	4	7	4	16	5	5	6	25	10	4	341
1976	14	30	32	15	1	3	0	14	21	15	15	5	16	24	12	10	15	1	5	8	3	6	9	6	7	27	40	7	382
1977	12	31	31	25	4	22	0	16	29	14	10	13	9	29	8	12	4	7	10	19	0	10	14	6	15	28	31	3	442
1978	14	24	42	21	6	22	0	0	32	15	8	7	9	19	3	3	3	11	2	10	0	8	8	6	10	24	40	20	411
1979	20	40	47	17	3	12	0	13	30	17	9	10	10	21	3	7	6	9	4	5	0	9	0	2	27	23	40	7	436
1980	0	37	31	17	3	6	0	5	25	16	15	13	21	15	3	3	6	11	3	7	3	9	2	6	30	30	30	17	391
1981	0	13	15	24	11	1	0	10	30	20	10	10	21	23	7	7	9	8	7	7	0	20	11	2	22	26	27	15	376
1982	19	35	29	13	13	0	0	9	44	42	7	11	28	28	4	14	13	5	6	7	2	14	11	1	12	27	46	14	452
1983	32	44	18	21	7	7	0	18	48	18	5	9	14	16	6	8	7	13	4	7	1	23	19	3	21	39	34	18	448
1984	29	34	21	48	18	7	0	18	49	28	5	12	17	33	13	11	16	13	10	7	3	21	17	33	22	44	53	11	587
1985	41	22	47	16	38	17	0	29	57	15	2	12	38	18	13	11	22	17	8	7	0	12	13	19	30	45	89	33	733
1986	43	28	25	48	18	26	0	35	18	21	6	6	16	28	11	10	18	39	7	14	2	9	11	28	11	29	74	124	670
1987	36	39	31	43	21	22	0	28	46	16	4	9	8	23	7	3	3	18	2	7	0	9	18	7	6	23	62	234	723
1988	37	45	46	67	26	11	1	37	57	21	11	7	11	36	6	11	16	19	1	12	2	23	17	5	18	19	66	272	916
1989	78	18	68	88	14	7	1	34	62	39	11	21	22	37	4	16	15	26	3	19	1	24	18	11	24	38	63	174	968
1990	122	86	63	90	11	17	1	30	54	23	12	19	22	36	13	11	20	42	11	8	0	15	15	9	18	33	62	82	957
1991	86	98	31	84	26	16	0	25	32	27	11	14	19	41	18	13	16	32	8	14	2	17	16	15	17	43	77	85	951
1992	122	77	74	98	32	14	0	99	56	26	16	12	15	33	18	18	27	48	2	25	2	24	19	23	22	54	91	65	1058
1993	128	109	148	154	45	48	0	58	120	28	16	15	31	26	43	32	32	80	7	23	3	38	33	17	18	58	106	49	1343
1994	102	83	78	91	58	99	1	88	52	26	8	25	24	35	18	12	18	36	2	19	1	24	31	29	19	43	144	52	1223
1995	76	87	100	132	36	77	0	58	65	35	7	19	28	32	18	14	35	106	3	21	4	29	31	33	16	44	137	65	1276
1996	76	143	97	147	35	72	0	22	56	27	2	19	23	14	29	19	42	92	0	9	1	28	21	25	6	28	136	113	1292
Total	1414	1409	1440	1641	478	561	6	794	1158	784	319	322	453	712	485	480	685	814	126	314	39	410	348	310	385	771	1615	1473	19299

TABLE D.3

ALL EXPLORATORY WELLS - AVERAGE DEPTH

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1947	2702	3187	2819	2236	0	926	0	3321	3602	6930	4158	3396	3912	4181	4924	3851	4291	1803	9811	7369	0	8746	5724	2975	0	2205	1965	179	5182
1948	2984	3679	3211	2780	1193	1922	0	5511	6853	7004	8582	0	0	6542	5789	5886	6398	3826	8188	6364	0	0	0	7575	811718	9847	0		4334
1949	3040	3651	4183	3347	2181	1756	0	5132	6855	5378	2830	0	0	6888	5558	5587	4321	4802	0	6241	0	0	0	6873	652611953	5914	0		4332
1950	2493	3693	3978	2526	3295	2369	0	5888	7165	5249	0	0	0	5504	5295	4985	4825	3582	0	5706	0	6484	0	5888	6799	8413	6448	5831	4802
1951	2797	3462	3382	2913	1163	1983	0	4979	5678	6195	10073	10898	9634	5982	5484	5117	4288	3458	0	5848	0	6518	0	5753	0	6473	5589	4793	4879
1952	3547	3795	3483	2936	1578	0	0	4389	6973	6837	7522	9301	8791	5484	5067	4796	4898	3269	7583	4498	0	6617	9638	4827	6588	9459	5217	4374	4388
1953	3155	3725	3332	2484	1488	3888	0	5718	6525	6815	10013	8971	8921	6118	5184	4368	4887	3485	8864	4878	9425	6588	0	4876	3742	9837	5389	4523	4693
1954	3174	3258	2888	2298	1188	0	0	5228	5369	6518	9828	10533	9812	5577	4911	4516	3813	4883	6955	5962	5818	7399	9551	4159	0	7895	5711	5939	5383
1955	3887	3459	3292	2544	0	0	0	7178	5162	6789	9612	9933	8888	5735	5482	4394	4368	3249	5961	4888	6955	6721	8679	3448	7835	9967	6287	6445	5588
1956	3812	3283	3163	3158	4814	1566	0	5847	6112	6853	9754	9729	7526	5474	4885	4884	4186	4979	6282	5182	7771	7736	8789	3286	6364	8865	5258	6381	5589
1957	3521	3319	3289	2488	1283	2548	0	6887	6492	6346	11257	9596	8999	5628	5461	4984	4673	3782	5968	5315	0	5922	10124	4798	7418	8754	5266	5675	5441
1958	3692	3531	3188	2692	2313	2579	0	5447	5888	6172	8821	10853	7986	6143	4796	4814	3579	3459	7958	5297	0	6888	12384	7655	8786	9161	5551	6313	5424
1959	3353	3452	3373	2759	2219	2446	0	5492	5188	6721	10425	8836	9388	5184	5258	4356	3563	3578	6716	5183	0	6657	11885	5528	8727	10697	5137	4689	5549
19	4314	3184	3456	2686	1682	3327	0	6175	5735	6971	9644	8586	8918	5684	5528	5026	3688	3553	6673	6283	13759	6857	13761	3881	8542	8967	6848	4544	5885
1961	3876	3276	3128	2425	1741	2532	0	6258	5653	6922	9876	9283	8851	5924	5159	5288	3543	3787	5157	6882	0	7879	12827	5555	8861	9351	5738	4884	6175
1962	3491	3868	3842	2381	1681	0	0	5866	5471	6487	11173	8789	7988	6496	5949	4881	3637	3781	4861	3585	7287	7585	10781	8148	8284	10878	6181	4126	5784
1963	3523	3379	2958	2397	1742	1348	0	6186	5248	6895	9518	10838	7177	6287	5988	5861	3812	3478	5115	4815	8828	6685	9422	4895	8223	9233	5673	4343	5187
1964	3391	3389	3852	2335	1837	1812	0	5647	5176	5748	7488	8559	7813	5867	5361	5372	3872	3861	4715	4726	10765	6761	9987	6899	7853	8158	5315	5716	5351
1965	3133	3245	2816	2888	1723	1595	0	5485	5265	5766	13868	9587	7998	5629	4488	5682	3668	2876	4748	5474	0	7111	9875	5823	7938	9114	5595	6892	4897
1966	3874	3451	3285	2849	1948	2881	0	5793	6192	5852	10688	9188	7788	5683	4846	5738	4293	2842	5193	5218	10285	7561	10124	5882	7912	8637	5267	5989	4978
1967	3358	3471	2989	2355	2289	2824	0	5885	5893	5678	8591	10475	8813	5669	4285	4979	3623	3821	3638	5458	0	6817	10168	5961	8113	7961	6887	3785	4957
1968	3284	3818	3893	2187	1872	3026	2887	6534	6782	5468	10663	11215	9923	5994	5879	5777	4498	2525	3528	4558	6433	6899	11366	5614	7653	8799	5189	5888	5012
1969	3319	3449	3863	2126	1972	2648	3255	4832	5827	5752	10158	12537	10892	5534	6818	5481	3612	2684	4525	4481	6588	6825	11887	4778	7619	9121	5385	5178	4995
1970	2898	2874	3868	2369	1873	2868	3355	5984	6429	5755	10888	12844	10884	6945	5967	6479	3172	3997	4884	6359	0	7875	13187	6328	8189	9882	5352	5278	4538
1971	3241	3888	3838	2341	1995	2657	0	4876	5288	5648	10588	11488	7999	6881	5848	5182	2797	2537	3844	4912	10588	8138	11388	3781	7255	7955	4767	5177	4858
1972	3782	3986	3985	2438	1757	1837	0	4829	5686	5819	10188	9723	8677	5413	4686	4126	3166	2387	7274	4426	9275	6513	11348	4896	7548	8431	5335	4916	4458
1973	2996	2985	2988	2252	1748	1421	0	4886	4133	5331	8985	8989	9589	5531	4119	4421	3285	2475	5252	5881	9364	6396	10123	3948	7199	7926	4536	4218	3988
1974	3348	3144	3825	2389	1878	1582	234	4298	4117	4818	8121	9521	7359	5188	4349	4153	3123	2326	3187	4866	9888	6186	10882	3452	6758	7558	5871	2527	4825
1975	2999	2981	3871	2298	1779	1445	0	4899	4774	4928	12469	9582	8188	5861	5391	4874	3117	2583	5898	4955	8683	7217	10878	2777	5555	8852	5116	1656	3939
1976	2532	2881	2945	2185	1827	1177	0	5399	4843	4859	5984	8742	7936	6872	5582	5483	2885	2389	0	6832	10436	7488	10585	3348	4386	7884	3828	1686	3218
Total	3118	3158	3895	2542	1828	1785	2432	4318	5866	5873	7789	9688	8179	5547	4737	4782	3666	2854	5478	5145	9561	6868	10542	4438	7778	8468	5149	4883	4823

TABLE 8.4

ALL EXPLORATORY WELLS - OIL SUCCESSES

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1947	1	0	0	0	0	0	0	3	0	0	0	0	0	0	0
1948	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1949	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
1950	0	0	0	0	0	0	0	2	1	1	0	0	0	1	0
1951	0	2	1	2	0	0	0	0	2	2	0	0	0	4	5
1952	0	1	1	0	0	0	0	0	3	3	0	0	0	4	4
1953	1	1	1	0	0	0	0	0	4	1	1	1	1	0	0
1954	1	0	3	1	0	0	0	0	0	1	1	1	2	0	0
1955	0	0	1	1	0	0	0	0	0	0	0	1	3	2	1
1956	0	0	0	1	0	0	0	0	0	1	2	1	1	1	0
1957	0	0	2	0	0	0	0	1	0	0	0	3	0	3	1
1958	2	2	1	0	0	0	0	0	2	1	0	1	0	2	0
1959	0	1	0	0	0	0	0	0	1	1	0	1	0	1	0
1960	1	0	0	0	0	0	0	0	1	5	2	2	2	0	0
1961	0	0	0	1	0	0	0	0	2	5	1	3	5	2	0
1962	2	1	1	1	0	0	0	0	0	1	0	2	2	1	0
1963	1	1	2	1	0	0	0	1	1	0	1	3	1	1	0
1964	2	0	0	1	0	0	0	0	0	1	1	2	5	3	0
1965	5	0	2	2	0	0	0	0	0	0	0	4	5	0	1
1966	1	1	4	1	0	0	0	6	1	0	0	0	4	0	0
1967	1	1	5	1	0	0	0	2	1	1	0	1	2	1	0
1968	2	1	2	2	0	0	0	2	1	0	0	2	0	5	0
1969	1	1	2	0	0	0	0	2	2	1	1	1	2	2	0
1970	4	5	1	0	0	0	0	2	1	2	0	2	1	2	0
1971	2	1	4	1	0	0	0	1	2	0	0	1	3	1	0
1972	1	1	2	0	0	0	0	1	1	1	0	1	1	1	0
1973	8	4	8	2	1	0	0	3	6	0	1	3	7	2	0
1974	1	0	0	2	0	0	0	2	3	1	1	7	9	3	1
1975	4	1	3	4	0	0	0	1	4	1	0	6	5	2	0
1976	2	0	2	1		0	0	0	4	1	0	12	4	1	0
Total	49	33	60	32	1	0	0	37	58	30	12	65	72	45	13
Ratio of Oil Finds Success	0.22	0.19	0.26	0.19	0.02	0.00	0.00	0.84	0.32	0.56	0.55	1.76	2.0	1.36	0.31

TABLE II.4 (Continued)

	16	17	18	19	20	21	22	24	24	25	26	27	28	Total	Ratio Oil to Gas Success
1947	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0.19
1948	2	2	0	0	0	0	0	0	0	0	0	0	0	4	0.80
1949	1	2	0	0	0	0	0	0	0	0	0	1	0	7	1.00
1950	0	0	0	0	0	0	0	0	0	0	0	0	0	15	1.67
1951	0	0	0	0	1	0	0	0	0	0	0	0	0	23	0.85
1952	2	1	0	0	0	0	0	0	0	0	0	0	0	22	0.69
1953	1	0	0	1	1	1	0	0	0	0	2	1	0	15	0.65
1954	1	0	0	1	1	2	0	0	0	0	2	0	0	19	0.90
1955	1	1	0	0	0	1	5	0	0	0	1	0	0	20	0.51
1956	1	0	0	1	1	1	0	0	0	0	1	1	0	17	0.61
1957	1	0	0	5	4	0	0	0	0	1	1	1	0	23	0.82
1958	1	0	0	0	0	0	0	0	2	5	1	3	0	23	0.77
1959	0	0	0	0	1	0	2	0	0	4	1	1	0	20	0.51
1960	0	0	0	0	2	0	1	0	3	5	2	0	0	23	0.56
1961	0	0	0	1	0	0	2	0	0	2	3	0	0	27	0.84
1962	0	0	0	0	0	0	1	0	0	4	4	1	0	26	0.67
1963	0	1	0	0	0	0	0	2	0	4	5	2	0	31	0.82
1964	0	0	0	5	0	1	0	1	11	3	1	3	0	44	0.90
1965	0	1	0	0	0	0	1	1	1	0	0	11	3	37	0.69
1966	1	0	0	0	0	0	1	0	0	0	2	4	21	47	1.68
1967	0	0	0	0	0	0	1	0	0	0	0	6	58	82	2.16
1968	2	1	0	1	1	1	1	0	0	0	0	1	73	105	1.98
1969	1	0	0	0	0	0	1	0	0	0	0	3	44	71	1.25
1970	0	0	0	0	0	0	0	0	0	4	1	4	10	34	0.37
1971	1	0	0	0	0	0	0	0	0	0	0	1	33	51	0.43
1972	0	0	0	0	0	0	1	1	0	0	3	2	5	26	0.20
1973	1	1	0	0	2	0	0	0	0	0	0	2	8	66	0.24
1974	0	0	0	0	1	0	1	1	0	0	0	2	4	53	0.39
1975	0	0	0	1	1	0	0	2	0	1	1	4	0	41	0.25
1976	0	1	0	0	1	0	1	1	0	0	0	2	1	44	0.21
Total	25	11	0	18	17	7	14	9	12	37	33	56	260	1009	
Ratio of Oil to Gas Success	0.93	0.17	0.0	4.5	1.7	2.33	0.7	0.06	1.2	7.4	1.03	1.33	9.67		

TABLE D.5

ALL EXPLORATORY WELLS - GAS SUCCESSES

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1947	7	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	21
1948	3	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
1949	0	0	2	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7
1950	2	3	0	2	0	0	0	0	0	0	0	0	0	1	0	0	2	0	0	0	0	0	0	0	0	0	0	0	9
1951	4	6	0	2	0	0	0	1	1	2	0	1	0	0	0	2	1	2	0	1	0	0	0	0	0	0	0	0	27
1952	0	2	1	5	6	0	0	1	1	0	1	0	3	2	5	1	1	5	1	0	0	0	0	0	0	0	3	0	32
1953	2	1	4	0	0	0	0	0	1	2	0	3	2	1	1	0	2	0	1	1	0	0	0	1	0	1	0	0	23
1954	1	1	5	2	0	0	0	0	4	1	0	1	0	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0	21
1955	1	4	1	2	0	0	0	0	11	2	0	1	4	3	0	2	3	3	0	1	0	1	0	0	0	0	0	0	39
1956	6	4	1	0	0	0	0	0	3	1	1	2	2	2	1	2	1	0	0	0	0	0	1	0	0	0	3	0	28
1957	1	7	3	1	0	0	0	1	5	1	1	2	0	0	0	1	0	0	1	1	0	0	2	0	0	1	0	0	28
1958	1	2	3	3	0	0	0	1	9	0	2	1	0	1	1	0	0	2	0	1	0	1	0	0	0	0	2	0	30
1959	3	4	4	0	2	0	0	3	0	1	2	3	2	1	0	2	0	0	0	0	0	0	0	0	0	0	2	0	39
1960	4	0	4	5	1	1	0	0	7	0	4	2	1	0	0	0	0	1	0	0	0	0	0	0	0	2	1	0	37
1961	1	3	0	2	4	0	0	1	5	0	0	2	4	2	0	0	0	0	0	0	0	0	0	0	0	3	2	0	41
1962	3	4	2	0	4	0	0	0	6	7	3	1	1	1	0	3	0	0	0	0	0	3	1	0	1	4	0	0	32
1963	4	5	1	3	0	0	0	1	6	1	1	0	1	1	0	3	2	1	0	0	0	1	2	0	0	0	0	0	39
1964	7	3	5	6	1	0	0	1	7	3	1	2	1	1	0	0	1	1	0	1	0	1	3	0	0	2	1	0	48
1965	8	1	12	2	1	0	0	2	6	2	0	0	6	1	0	0	3	1	0	0	1	0	2	0	0	4	2	0	69
1966	2	1	2	0	3	0	0	2	1	1	1	0	1	0	0	0	3	4	0	1	0	0	1	0	0	2	1	1	54
1967	3	9	3	0	0	0	0	1	2	2	1	0	0	2	0	0	2	2	0	0	0	2	0	0	1	0	0	2	28
1968	6	2	6	7	0	0	0	1	6	3	1	2	1	0	0	0	0	2	0	1	0	3	1	0	0	0	2	3	38
1969	14	14	2	6	0	0	0	1	6	6	1	2	1	0	0	0	0	2	0	1	0	3	1	0	0	0	2	3	55
1970	14	34	6	15	1	0	0	0	3	4	1	2	2	3	1	0	5	3	0	0	0	1	0	0	0	0	0	1	97
1971	3	41	15	10	2	0	0	0	1	6	1	1	1	4	5	0	3	9	0	1	0	2	0	0	0	1	3	0	105
1972	10	37	13	16	5	1	0	2	10	2	0	0	1	0	3	1	4	11	0	0	0	2	0	5	1	1	2	1	120
1973	30	99	49	24	3	2	0	1	18	1	0	5	1	1	11	2	3	12	1	1	0	3	4	0	0	0	3	4	278
1974	11	27	22	20	1	0	0	7	12	2	0	2	0	3	1	2	5	6	0	0	0	2	2	0	0	0	6	5	136
1975	29	29	32	26	1	0	0	6	7	3	0	0	1	1	3	2	9	13	0	0	0	1	2	1	0	0	4	3	161
1976	90	56	26	28	2	3	0	5	11	1	0	2	1	0	12	5	9	5	0	0	0	1	0	0	1	0	1	5	212
Total	319	489	227	195	55	6	0	38	156	52	22	57	36	35	62	27	63	83	4	10	1	27	25	10	5	32	42	27	1982

TABLE D.6

PENETRATIONS TO THE LEDUC (D-3) FORMATION

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1947	0	0	1	0	0	0	0	0	0	1	0	0	0	0	0	1	2	0	0	0	0	0	0	0	0	1	0	0	5
1948	0	0	2	0	0	0	0	0	0	0	0	0	0	1	2	1	6	1	0	0	0	0	0	0	0	1	0	0	14
1949	1	0	9	5	1	2	0	0	1	2	0	0	0	2	1	3	12	13	0	0	0	0	0	2	0	0	3	0	55
1950	0	1	5	2	0	0	0	0	1	2	0	0	0	4	0	2	1	5	0	0	0	0	0	0	0	0	4	0	27
1951	0	1	8	1	0	2	0	0	7	8	2	2	0	9	4	6	4	8	0	0	0	0	0	2	0	1	7	0	72
1952	0	2	9	5	0	0	0	0	5	10	0	0	2	12	5	5	5	5	0	0	0	0	0	0	0	2	5	0	63
1953	0	1	10	4	0	0	0	0	10	8	0	2	2	2	0	2	4	3	0	0	0	0	0	1	0	3	2	0	48
1954	0	1	2	0	0	0	0	0	11	5	1	4	2	3	0	1	6	0	0	0	0	0	1	0	0	4	2	0	45
1955	0	1	5	1	0	0	0	1	5	4	0	2	1	15	1	3	10	6	0	0	0	1	1	1	0	9	2	0	67
1956	0	0	5	1	0	0	0	0	3	10	0	2	2	9	0	2	4	0	0	0	0	1	3	1	0	1	3	0	45
1957	0	0	13	1	0	0	0	0	3	6	0	6	0	10	1	1	0	0	0	0	0	1	8	1	0	3	7	0	61
1958	0	0	1	0	0	0	0	0	4	4	0	4	0	8	0	1	0	5	0	0	0	0	5	0	0	5	5	0	42
1959	0	0	3	3	0	2	0	0	6	6	0	5	1	7	0	0	0	3	0	0	0	0	2	0	0	6	6	0	58
1960	0	0	3	0	0	0	0	0	3	7	0	1	1	3	0	0	1	0	0	0	0	0	0	0	0	3	12	0	34
1961	0	0	1	1	1	1	0	0	4	11	0	7	1	5	0	1	1	0	0	0	0	1	7	0	0	3	5	0	50
1962	0	0	4	3	0	0	0	0	4	11	0	1	1	14	1	0	3	0	0	0	0	0	4	0	0	0	6	0	52
1963	0	0	3	4	0	2	0	0	7	2	0	2	0	5	0	0	2	0	0	0	0	0	3	0	0	4	3	0	37
1964	0	0	7	1	1	0	0	0	4	5	0	3	0	10	0	1	4	0	0	0	0	0	4	4	0	3	1	0	58
1965	0	1	10	0	0	2	0	0	4	6	0	6	0	8	0	1	5	0	0	0	0	0	1	0	0	3	2	0	47
1966	0	0	0	0	0	0	0	0	0	5	0	0	0	8	2	2	2	2	0	0	0	0	4	0	0	2	5	0	32
1967	0	0	1	0	0	1	0	0	1	2	0	6	0	9	0	2	1	2	0	0	0	0	2	0	0	2	2	0	51
1968	0	0	3	2	0	0	0	0	3	9	0	4	2	24	2	5	2	0	0	0	0	0	5	0	0	1	5	0	62
1969	0	0	2	0	0	0	0	0	8	12	0	15	4	15	1	1	4	0	0	0	0	0	8	0	0	5	2	0	77
1970	0	0	1	5	0	1	0	0	3	7	3	12	4	9	0	0	2	0	0	0	0	0	6	0	0	6	1	0	60
1971	0	0	6	2	0	1	0	0	2	4	0	7	0	6	0	0	2	2	0	0	0	1	2	0	0	2	2	0	39
1972	0	0	0	0	0	0	0	0	2	2	2	3	2	7	5	2	0	1	0	0	0	1	2	0	1	7	4	0	91
1973	0	0	1	0	0	0	0	0	3	7	1	2	1	8	2	3	4	0	0	0	0	1	3	0	0	3	6	0	65
1974	0	0	1	0	0	6	0	2	3	0	0	7	1	6	1	0	0	0	0	0	0	0	2	0	0	2	6	0	37
1975	0	0	1	0	0	1	0	0	0	0	2	6	0	5	0	3	3	0	0	0	0	1	2	0	0	4	4	0	29
1976	0	0	1	0	0	1	0	0	1	0	0	1	0	1	0	0	0	0	0	0	0	1	4	0	0	0	7	0	17
Total	1	8	109	17	3	22	0	3	108	151	11	110	27	239	28	46	28	56	0	0	0	9	79	12	1	87	119	0	1354

TABLE D.7

PENETRATIONS TO THE NISKU (D-2) FORMATION

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1947	0	0	1	0	0	0	0	0	0	1	0	0	0	0	6	5	3	0	1	1	0	1	0	0	0	0	0	0	
1948	0	0	3	0	0	0	0	0	0	1	0	0	0	2	5	11	17	1	1	7	0	0	0	1	0	0	0	0	49
1949	0	1	11	2	0	1	0	0	2	4	0	0	0	7	7	26	28	17	0	7	0	0	0	4	0	0	0	0	117
1950	0	1	5	5	0	0	0	0	1	7	0	0	0	23	16	19	15	9	0	5	0	0	0	3	1	1	1	0	110
1951	0	1	3	4	0	2	0	0	9	19	2	2	1	19	24	37	15	12	0	7	0	0	0	2	0	0	2	1	162
1952	0	1	3	1	0	0	0	0	6	15	0	1	3	24	33	36	12	15	2	2	0	2	0	2	0	0	4	0	164
1953	0	0	0	2	0	0	0	0	16	19	0	3	8	19	15	11	7	7	1	1	1	0	0	3	0	2	0	9	123
1954	0	0	1	0	0	0	0	0	12	13	1	4	5	14	5	6	8	1	2	4	0	7	1	2	0	0	0	0	86
1955	0	0	3	1	0	0	0	1	7	8	0	4	5	21	5	12	13	11	0	1	0	5	1	3	2	0	0	0	103
1956	0	0	5	2	0	0	0	0	5	11	0	3	3	17	9	10	11	1	1	2	0	2	3	2	2	0	2	0	91
1957	0	0	10	2	0	1	0	0	5	11	0	9	2	10	4	9	5	5	0	2	0	1	6	3	7	1	0	0	97
1958	0	0	13	4	0	2	0	0	5	9	0	4	1	18	2	1	1	6	1	2	0	1	4	3	7	0	1	0	85
1959	0	1	10	3	1	2	0	0	8	14	0	10	2	12	2	3	3	7	1	0	0	1	2	0	4	0	0	0	86
1960	0	0	7	0	0	1	0	0	5	14	0	2	7	11	2	2	5	5	0	1	2	1	0	0	1	0	1	0	77
1961	0	0	2	1	0	0	0	0	5	24	0	0	3	16	6	5	4	5	1	2	0	4	2	0	2	0	0	0	90
1962	0	0	4	0	0	0	0	0	6	27	0	3	3	25	2	9	10	4	1	0	0	2	2	0	1	0	3	0	102
1963	0	0	3	1	0	0	0	0	6	8	0	5	0	13	4	7	5	8	0	2	0	3	0	1	0	0	2	1	73
1964	0	0	5	5	0	1	0	0	7	7	0	5	0	28	9	9	14	12	2	5	0	2	1	29	0	1	4	0	142
1965	0	0	9	2	0	3	0	0	8	10	0	8	0	11	4	9	19	21	0	2	0	0	3	14	7	0	34	1	165
1966	1	0	1	1	0	3	0	0	4	11	1	1	0	16	6	10	8	23	1	0	0	2	2	13	2	1	8	1	120
1967	0	0	2	2	0	4	0	0	2	3	0	4	1	18	3	3	3	6	0	1	0	1	0	5	1	0	17	4	84
1968	0	0	5	1	0	0	0	0	3	7	0	4	5	31	5	10	14	8	0	0	0	0	0	3	3	0	14	12	125
1969	0	0	5	7	0	1	0	0	10	16	0	15	4	28	4	15	10	9	0	1	0	3	5	2	4	4	9	2	156
1970	0	0	1	10	0	3	0	0	9	14	3	15	9	15	3	6	12	21	0	0	0	0	2	5	4	6	6	1	147
1971	0	0	7	11	0	1	0	0	6	9	0	8	1	11	2	9	6	14	0	2	0	2	1	2	7	10	4	0	113
1972	0	1	7	12	0	2	0	0	6	6	2	4	4	16	7	11	10	20	0	7	0	4	2	9	6	9	9	0	147
1973	0	0	6	11	0	2	0	0	7	8	1	3	6	15	16	18	11	19	2	1	1	2	3	3	8	5	9	0	156
1974	0	0	2	5	0	0	0	2	2	3	0	8	3	13	7	5	8	18	0	1	0	0	1	8	4	5	5	0	109
1975	0	0	7	8	0	11	0	1	1	2	2	7	2	8	2	4	9	10	0	1	0	1	1	0	1	6	1	0	85
1976	0	0	10	15	0	3	0	0	1	2	0	1	1	2	5	2	10	21	0	0	0	1	0	2	0	0	12	0	88
Total	1	8	159	127	1	53	0	4	142	301	12	143	79	473	222	320	294	316	17	67	4	48	42	124	78	51	138	27	3273

TABLE D.8

PENETRATIONS TO THE VIKING FORMATION

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1947	0	1	9	23	0	0	0	0	1	1	0	0	0	1	6	9	5	0	1	2	0	0	0	2	0	0	0	0	61
1948	0	1	5	19	0	0	0	0	0	1	0	0	0	3	6	11	19	1	1	6	0	0	0	1	0	0	0	0	74
1949	0	4	11	13	3	0	0	0	2	6	0	0	0	7	7	29	29	9	0	9	0	0	0	3	1	0	0	0	133
1950	0	8	8	9	1	0	0	0	2	10	0	0	0	24	15	25	16	6	0	7	0	0	0	3	0	0	1	0	133
1951	0	21	14	8	0	0	0	0	13	22	1	1	1	18	27	47	25	12	0	7	0	1	0	5	0	0	1	0	222
1952	0	18	21	23	9	0	0	0	14	15	0	1	2	24	49	54	17	15	3	5	0	1	0	3	0	0	0	0	276
1953	0	15	35	10	3	0	0	0	19	16	1	2	7	19	20	21	13	8	3	6	1	1	0	4	0	0	0	0	204
1954	1	16	36	7	0	0	0	1	22	13	4	4	10	20	10	13	10	1	7	5	1	19	1	3	0	0	0	0	206
1955	4	17	18	8	0	0	0	1	17	9	3	8	10	32	8	15	16	12	3	4	1	6	1	7	2	0	0	0	202
1956	7	19	23	11	0	0	0	1	23	15	7	7	13	24	11	16	15	1	4	8	1	3	4	4	4	0	1	0	221
1957	1	24	29	9	0	0	0	0	14	14	3	12	6	29	7	12	4	5	8	15	0	6	7	4	12	4	0	0	227
1958	0	18	35	16	2	1	0	0	31	14	4	6	5	18	3	3	3	13	2	7	0	5	5	6	18	4	1	0	220
1959	0	30	39	12	3	0	0	0	36	17	4	12	7	20	3	7	4	5	4	5	0	8	5	2	27	9	0	0	259
1960	0	21	23	13	2	0	0	0	27	16	8	10	15	15	3	3	6	6	3	7	1	3	0	6	36	12	4	0	234
1961	2	6	10	23	1	0	0	0	18	25	4	15	12	25	7	7	9	2	3	6	0	12	6	2	22	16	3	0	234
1962	0	11	27	9	1	0	0	0	29	42	2	8	21	28	3	14	13	3	1	6	1	11	10	1	11	9	1	0	262
1963	1	32	17	15	0	0	0	0	29	9	5	8	11	16	6	8	7	9	1	6	1	10	10	2	20	20	8	0	237
1964	0	25	17	25	2	0	0	0	34	20	3	9	15	32	12	11	16	12	4	5	2	10	15	32	19	15	5	0	336
1965	0	10	34	20	3	0	0	0	18	15	0	11	22	17	10	10	20	24	2	7	0	7	10	18	24	16	23	0	329
1966	0	7	16	14	5	0	0	0	11	14	2	1	14	14	9	8	5	22	5	8	1	6	7	16	11	16	12	0	220
1967	0	9	9	3	0	0	0	0	9	9	1	2	5	18	6	3	0	12	0	2	0	2	4	5	2	8	6	0	115
1968	0	18	13	5	4	0	0	0	7	10	0	2	3	22	5	9	8	10	0	4	0	8	5	2	7	1	2	0	145
1969	0	25	23	10	2	0	0	0	10	18	2	9	6	30	3	9	8	13	0	10	0	12	5	9	9	6	1	0	220
1970	0	31	27	25	5	0	0	0	9	15	0	6	9	31	13	10	19	51	1	8	0	6	2	7	8	7	2	0	290
1971	0	40	33	28	5	0	0	0	12	11	0	1	4	21	14	5	9	25	0	8	0	2	1	11	6	7	0	0	243
1972	0	31	27	29	7	0	0	0	12	10	5	3	6	20	10	10	11	45	1	18	1	2	9	5	8	8	0	0	278
1973	0	80	33	70	14	6	0	0	23	18	7	6	16	13	38	15	25	58	3	15	2	18	18	1	5	2	2	0	490
1974	0	25	24	26	20	10	0	0	5	9	1	13	11	14	4	4	13	39	0	6	1	14	13	7	10	5	13	0	285
1975	0	12	21	33	15	11	0	0	0	15	2	12	3	18	0	7	18	89	2	17	2	17	19	25	8	8	1	0	368
1976	0	29	19	43	13	4	0	0	0	8	1	13	12	2	5	7	16	86	0	4	1	15	15	19	2	1	1	0	316
Total	16	602	658	559	120	32	0	3	459	413	68	184	259	575	318	400	377	596	60	221	17	283	174	217	268	172	80	0	7043

TABLE D.9

PENETRATIONS TO THE CARDIUM FORMATION

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1947	0	0	0	0	0	0	0	2	3	0	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
1948	0	0	0	0	0	0	0	0	1	0	7	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	42
1949	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1950	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0
1951	0	0	0	0	0	0	0	0	0	1	1	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
1952	0	2	0	0	0	0	0	0	1	1	1	2	1	0	2	0	0	0	2	0	0	0	1	0	0	0	0	0	11
1953	0	0	0	0	0	0	0	0	0	1	1	2	5	1	0	0	0	0	2	2	1	2	0	0	1	1	1	0	20
1954	0	0	0	0	0	0	0	1	2	1	10	4	17	2	1	2	1	0	9	3	5	17	3	0	0	14	0	0	92
1955	0	0	0	0	0	0	0	1	1	1	6	8	18	3	1	1	1	3	4	2	4	8	4	0	0	11	1	0	86
1956	0	0	0	0	0	0	0	1	1	0	12	6	13	2	1	0	2	0	5	1	3	3	7	0	0	14	0	0	73
1957	0	0	0	0	0	0	0	1	1	0	9	6	5	1	2	0	0	0	10	8	0	4	12	0	1	7	1	0	68
1958	0	0	0	0	0	0	0	0	0	0	4	3	7	0	0	0	0	0	2	3	0	5	8	0	2	15	0	0	47
1959	0	0	0	0	0	0	0	2	2	0	2	7	7	0	0	0	0	0	4	3	0	7	6	0	2	14	0	0	58
1960	0	0	0	0	0	0	0	0	1	0	3	8	19	0	0	0	0	0	3	7	1	9	2	0	1	14	0	0	69
1961	0	0	0	0	0	0	0	1	1	0	2	5	15	1	0	0	0	0	6	0	0	11	13	1	0	12	0	0	68
1962	0	0	0	0	0	0	0	0	2	0	1	6	31	4	1	0	0	0	3	2	2	10	10	0	2	13	0	0	91
1963	0	0	0	0	0	0	0	0	0	0	1	5	14	0	2	0	0	0	4	3	1	10	16	0	0	19	0	0	87
1964	0	0	0	0	0	0	0	0	0	0	0	6	16	1	3	0	0	0	8	1	1	17	16	0	1	23	0	0	93
1965	0	0	0	0	0	0	0	0	0	0	0	6	11	0	2	0	0	0	3	2	0	10	12	0	3	18	0	0	69
1966	0	0	0	0	0	0	0	0	1	0	1	3	15	0	0	0	0	0	4	2	2	8	10	0	0	14	0	0	60
1967	0	0	0	0	0	0	0	0	1	0	2	7	8	0	0	0	0	0	0	1	0	5	9	0	0	14	0	0	48
1968	0	0	0	0	0	0	0	1	0	0	3	4	18	0	1	0	0	0	0	0	1	3	16	0	2	9	0	0	55
1969	0	0	0	0	0	0	0	0	0	0	0	20	22	0	1	0	0	0	3	0	1	17	14	0	0	13	0	0	94
1970	0	0	0	0	0	0	0	1	0	1	0	17	17	0	0	0	0	0	2	0	0	6	14	0	0	17	0	0	84
1971	0	0	0	0	0	0	0	5	1	0	17	9	15	0	0	0	0	0	1	4	1	8	14	0	1	15	1	0	92
1972	0	0	0	0	0	0	0	0	0	0	9	15	14	0	0	1	0	0	2	1	2	14	19	0	0	14	0	0	86
1973	0	0	0	0	0	0	0	3	1	0	10	13	24	0	0	0	0	0	3	7	3	25	30	0	2	16	1	0	138
1974	0	0	0	0	0	0	0	4	0	0	6	21	20	1	0	0	0	0	3	1	1	14	28	0	0	15	0	0	113
1975	0	0	0	0	0	0	0	2	0	0	4	14	13	1	0	0	0	0	2	6	4	18	31	0	0	19	0	0	119
1976	0	0	0	0	0	0	0	0	0	0	1	18	19	0	0	0	0	0	0	1	1	15	21	0	0	9	0	0	85
Total	0	0	0	0	0	0	0	27	20	6	181	212	384	17	17	4	4	3	83	63	34	246	318	1	20	334	5	0	1987

TABLE D.10

PENETRATIONS TO THE GRANITE WASH FORMATION

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1948	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	2
1949	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	2
1950	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	13	0	13
1951	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	11	3	16
1952	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	12	1	14
1953	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	2	2	1	5
1954	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11	3	4	18
1955	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	14	2	1	21
1956	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	6	7	1	15
1957	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	2	1	15	0	20
1958	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	0	4	24	1	42
1959	0	0	0	0	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	3	9	1	17
1960	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	2	14	2	21
1961	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	1	1	8	1	17
1962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	11	0	12
1963	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	10	1	12
1964	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	2	3	24	1	32
1965	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	7	47	2	60
1966	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	34	5	41
1967	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	21	10	33
1968	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	22	7	32
1969	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	5	26	1	35
1970	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	28	1	32
1971	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23	0	23
1972	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	4	16	0	21
1973	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	11	0	12
1974	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	21	1	24
1975	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	36	0	39
1976	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	27	0	28
Total	0	0	0	0	2	16	1	0	0	0	0	0	0	0	0	0	1	1	0	0	0	1	0	7	20	81	484	52	669

TABLE D.11

PENETRATIONS TO THE BEAVERHILL LAKE FORMATION

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1947	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	0	4
1948	0	0	0	1	0	1	0	0	0	1	0	0	0	0	0	3	0	0	0	0	0	0	0	1	0	1	0	0	12
1949	0	0	4	11	1	1	0	1	0	0	0	0	0	0	0	3	4	0	0	0	0	0	0	1	0	1	0	0	26
1950	0	0	1	2	1	1	0	0	0	0	0	0	0	0	0	2	1	11	0	0	0	0	0	0	0	0	2	0	44
1951	0	0	1	4	0	0	0	0	1	4	0	0	1	2	2	7	3	4	0	1	0	0	0	1	1	0	6	2	21
1952	1	0	3	1	1	0	0	0	3	2	0	1	1	0	3	7	2	6	0	0	0	0	0	1	0	1	4	5	43
1953	0	0	2	3	3	1	0	0	0	1	0	0	2	4	1	3	2	6	0	0	0	1	0	0	0	0	0	0	40
1954	0	0	0	1	0	0	0	1	0	1	0	0	2	4	1	1	3	0	1	0	0	0	0	1	0	0	2	2	27
1955	0	0	2	0	0	0	0	0	0	1	0	0	2	2	2	1	1	1	1	2	0	5	0	0	0	3	1	2	29
1956	0	0	1	1	1	2	0	1	1	1	0	0	1	5	1	1	2	3	0	0	0	1	1	0	1	1	3	1	35
1957	1	1	1	2	1	16	0	1	1	1	0	0	2	1	2	0	1	0	1	1	1	0	2	1	1	2	1	10	4	48
1958	1	2	1	1	2	10	0	0	0	0	0	2	1	1	2	2	0	1	0	0	0	0	0	2	0	1	10	2	76
1959	1	1	1	0	1	0	0	0	1	1	0	1	1	1	1	1	1	0	1	1	0	2	1	0	1	0	0	0	110
1960	3	1	3	2	1	1	0	1	0	0	0	0	1	1	0	0	1	4	1	0	0	1	3	1	26	9	10	0	90
1961	4	1	0	10	1	0	0	0	2	1	0	1	0	1	0	2	2	2	0	1	2	1	0	1	29	14	13	4	99
1962	2	0	3	4	1	0	0	0	0	1	0	1	0	4	1	3	0	3	1	1	0	4	4	1	21	15	7	4	93
1963	2	1	0	2	2	5	0	0	0	2	0	2	0	1	0	5	2	2	0	0	0	4	5	1	12	23	19	2	93
1964	1	0	1	4	1	0	0	1	1	0	0	1	0	1	1	1	2	2	2	4	0	4	1	11	20	18	30	4	139
1965	1	0	0	2	17	3	0	0	0	0	0	1	0	0	0	3	3	5	1	1	0	3	0	15	29	26	48	10	188
1966	0	1	2	1	1	3	0	0	0	1	1	0	0	0	0	1	1	3	1	0	0	2	0	14	11	14	51	111	221
1967	1	1	2	5	0	6	0	0	0	2	0	0	1	2	0	0	1	0	0	1	0	1	4	6	5	10	35	217	306
1968	1	9	1	0	2	1	1	1	1	1	0	2	0	0	0	1	1	7	0	0	0	3	13	4	14	7	34	248	349
1969	4	7	4	1	1	5	1	1	2	1	0	4	3	0	0	1	0	4	0	0	0	4	5	4	18	11	34	152	271
1970	3	2	5	10	0	7	1	1	1	0	1	9	9	0	1	0	0	2	0	0	0	3	4	4	11	18	39	73	204
1971	2	1	1	0	2	11	0	1	2	3	1	5	1	1	0	1	0	3	0	1	0	0	7	2	5	18	26	79	189
1972	2	1	2	6	2	1	0	0	1	0	0	1	2	1	0	1	0	2	0	0	0	1	6	3	15	19	25	37	129
1973	0	0	0	4	2	8	0	0	0	0	0	1	4	0	0	1	1	1	2	0	0	1	4	3	8	15	22	34	111
1974	2	2	0	3	17	29	1	1	0	0	0	4	1	0	0	1	0	0	0	0	0	1	3	0	8	9	29	12	123
1975	0	0	1	4	2	27	0	0	0	1	1	3	0	0	0	0	0	1	0	0	0	4	7	0	3	12	27	5	100
1976	0	1	0	4	1	16	0	0	1	0	0	0	1	0	0	0	0	0	0	0	0	2	0	3	0	7	24	4	72
Total	33	32	46	119	74	179	4	11	24	46	4	43	39	37	16	56	37	74	13	14	2	70	80	107	283	289	594	1021	1348

TABLE D.12

PENETRATIONS TO THE SLAVE POINT FORMATION

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1948	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
1949	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0	4	2	7
1950	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	5	9	15
1951	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11	3	14
1952	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	4	7
1953	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	3	6	10
1954	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	4	3	4	12
1955	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	1	2	8	7	19
1956	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	18	3	26
1957	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	38	17	59
1958	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	14	5	20
1959	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	1	0	16	16	34
1960	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	6	15	22
1961	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	18	14	33
1962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	2	15	13	29
1963	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	3	3	33	11	61
1964	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	1	0	0	0	0	0	5	0	5	70	38	125
1965	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	5	1	51	121	195
1966	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	2	2	2	37	228	287
1967	0	0	0	1	3	10	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	2	2	2	56	269	324
1968	0	0	0	2	3	5	1	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	1	2	1	41	172	230
1969	0	0	0	0	0	10	1	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	3	0	0	43	81	134
1970	0	0	0	1	0	4	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	0	1	25	85	121
1971	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	1	0	0	0	2	1	2	25	40	78
1972	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	1	2	21	33	61
1973	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	30	14	47
1974	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	24	4	30
1975	0	0	0	0	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	1	24	4	33
1976	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	6	8	50	3	0	0	0	0	0	0	0	0	0	2	21	0	1	0	0	2	30	32	33	627	1251	2012

TABLE D.13

PENETRATIONS TO THE KEG RIVER FORMATION

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1948	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1949	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
1950	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
1951	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	3
1952	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	7	8
1953	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	1	3
1954	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2
1955	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
1956	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2
1957	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	4	7
1958	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	7	1	12
1959	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	13	37
1960	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	7	5	14
1961	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	11	13	26
1962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	7	10
1963	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	4	5
1964	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	4	4	9
1965	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	18	0	0	12	7	38
1966	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	8	3	1	32	26	71
1967	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	0	1	32	120	163
1968	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	3	0	0	24	222	252
1969	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	1	0	23	259	287
1970	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	25	164	198
1971	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	18	77	111
1972	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	46	61
1973	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	1	0	7	35	46
1974	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	25	30
1975	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	9	14
1976	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	3	4
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	10	2	14
Total	0	0	0	7	2	11	2	0	0	0	0	0	0	0	0	0	0	4	0	1	0	0	0	48	9	2	269	1083	1457

TABLE D.14

PENETRATIONS TO THE SULPHUR POINT FORMATION

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	Total
1947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1948	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1949	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1950	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2
1951	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
1952	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
1953	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2
1954	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
1955	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2
1956	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
1957	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
1958	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
1959	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1960	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2
1961	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
1962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1963	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2
1964	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	21
1965	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	92	92
1966	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	203	203
1967	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	233	233
1968	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	145	146
1969	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	65	65
1970	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	77	77
1971	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	37	38
1972	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	25	26
1973	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	10
1974	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4
1975	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
1976	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	2	943	946

Footnotes

[1]This geographical anatomy is that utilized by the ERCB with respect to their computerized well data.

[2]See F. H. Lahee, Statistics of Exploratory Drilling in the United States 1945-1960, (American Association of Petroleum Geologists: 1962).

[3]The tedious process of 'unpacking' the data from its hexi-decimal IBM format into a configuration compatible with the University of Calgary's Honeywell Multics system was facilitated by the Consulting Division of the Computer Services Department. In particular the efforts of Steve Harris are acknowledged.

CANADIAN ENERGY RESEARCH INSTITUTE

PUBLICATIONS

Studies

No. 1 The Availability of Capital to Fund the Development of Canadian Energy Supplies. J. R. Downs. November 1977 (Price $3.00, 109 Pages) ISBN 0-920522-00-9.

No. 2 The Industrial Demand for Oil and Gas in Ontario. DataMetrics Limited. March 1978 (Price $3.00, 119 pages) ISBN 0-920522-01-7.

No. 3 The Effects of Rising Energy Costs on Canadian Industry. Anthony P. Ellison. April 1979 (Price $3.00, 62 pages) ISBN 0-920522-02-5.

No. 4 Potential Markets for Thermal Coal in Canada, 1978-2000: Summary and Conclusions. Canadian Resourcecon Limited. June 1979 (Price $3.00, 27 pages) ISBN 0-920522-03-3.

No. 5 Energy in Canada: Review and Outlook to 1995. W. Brent Friedenberg. July 1979 (Price $10.00, 140 pages) ISBN 0-920522-04-1.

No. 6 Energy Policy and the Balance of Payments: An Outline of the Issues. T. L. Powrie. July 1979 (Price $3.00, 61 pages) ISBN 0-920522-05-X.

No. 7 Oil and Gas Finding Costs. Russell S. Uhler. September 1379 (Price $3.00, 75 pages) ISBN 0-920522-06-8.

No. 8 Energy Use in Canada in Comparison with Other Countries. Z. Charles Slagorsky. October 1979 (Price $3.00, 91 pages) ISBN 0-920522-07-6.

No. 9 Enhanced Oil Recovery Potential in Canada. J. Philip Prince. March 1980 (Price $10.00, 332 pages) ISBN 0-920522-09-2.

Conclusions and Policy Implications from Enhanced Oil Recovery Potential in Canada, Study No. 9. J. Philip Prince. March 1980 (Price $3.00, 32 pages) ISBN 0-920522-10-6.

No. 10 The Impact of Rate Structure Change on Electricity Demand: A Case Study of Calgary Power Limited. Gerard J. Protti and Robert N. McRae. April 1980 (Price $10.00, 182 pages) ISBN 0-920522-11-4.

Overview and Summary from the Impact of Rate Structure Change on Electricity Demand: A Case Study of Calgary Power Limited. Gerard J. Protti and Robert N. McRae. April 1980 (Price $3.00, 14 pages) ISBN 0-920522-12-2.

No. 11 The Impact of a Sharp Oil Price Increase. G. E. Angevine. June 1980 (Price $10.00, 122 pages) ISBN 0-920522-13-0.

No. 12 Benefits and Costs of Oil Self-Sufficiency in Canada. J. A. Dawson and Z. C. Slagorsky. February 1981 (Price $10.00, 97 pages) ISBN 0-920522-15-7.

No. 13 Financing Canadian Energy Resource Development. J. A. Dawson. December 1981 (Price $10.00, 68 pages) ISBN 0-920522-17-3.

No. 14 Impacts of Canada's Uranium Mining Industry. Marvin Shaffer and Associates Ltd. May 1982 (Price $10.00, 87 pages) ISBN 0-920522-20-3.

No. 15 Coal and Nuclear Electricity Fuels: A Regional Analysis. Farhood Rahnama. June 1982 (Price $10.00, 80 pages) ISBN 0-920522-21-1.

No. 16 Alternative Transportation Fuels in Canada. Z. Charles Slagorsky. July 1982 (Price $10.00, 112 pages) ISBN 0-920522-23-8.

No. 17 Energy and Regional Investment in Canada. Gordon W. Douglas and Ellen F. Battle. March 1983 (Price $20.00, 114 pages) ISBN 0-920522-28-9.

No. 18 Household Energy Savings: Options for the Future. Brian D. Sumner and Barbara E. Green. March 1983 (Price $20.00, 194 pages) ISBN 0-920522-27-0.

No. 19 Modelling Exploration Success in Alberta Oil Plays. Kenneth D. Foat and Alan J. MacFadyen. September 1983 (Price $15.00, 181 pages) ISBN 0-920522-29-7.

Client Research Reports

81-1 Models for Energy Policy Analysis: A Survey. Kenneth D. Foat, Gerard J. Protti and Gordon W. Douglas. July 1981 (Price $10.00, 121 pages) ISBN 0-920522-16-5.

82-1 The Economics of Improved Energy Efficiency in New Calgary Housing. Barbara E. Green. March 1982 (Price $10.00, 55 pages) ISBN 0-920522-18-1.

82-2 Interregional Economic Impacts of the Alberta Alsands Project. Gordon W. Douglas and J. A. MacMillan. September 1982 (Price $15.00, 78 pages) ISBN 0-920522-24-6.

83-1 Potential Benefits and Costs of Canadian Electricity Exports. Ellen F. Battle, Gordon S. Gislason and Gordon W. Douglas. April 1983 (Price $25.00, 288 pages) ISBN 0-920522-26-2.

Working Papers

78-1 Drilling and Field Construction Costs in the Canadian Petroleum Industry. Gordon M. Engbloom, Confer Consulting Limited. January 1978 (Price $3.00, 83 pages).

78-2 Some Supply Price Estimates for Synthetic Crude Oil in Canada. Z. Charles Slagorsky. April 1978 (Price $3.00, 42 pages).

78-3 Past and Future Energy Costs in the Canadian Economy. Anthony P. Ellison. April 1978 (Price $5.00, 136 pages).

78-4 Canadian Electric Utility Industry Costs, 1960-1990. Gerard J. Protti. May 1978 (Price $10.00, 218 pages).

78-5 Enhanced Oil Recovery Potential in Canada--A Methodological Preview. J. Philip Prince. June 1978 (Price $10.00, 184 pages).

78-6 Regional Energy and Production Data for Canadian Manufacturing Industries: 1962-74. Robert N. McRae and Alan R. Webster. July 1978 (Price $5.00, 106 pages).

78-7 Regional Demand for Energy by Canadian Manufacturing Industries. Robert N. McRae. October 1978 (Price $5.00, 132 pages).

79-1 An Input-Output Analysis of the Effects of Rising Energy Costs on Canadian Industries. Anthony P. Ellison. April 1979 (Price $10.00, 246 pages).

79-2 Potential Markets for Thermal Coal in Canada, 1978-2000. Canadian Resourcecon Limited. June 1979 (Price $15.00, 321 pages).

79-3 Inter-City Comparisons of Canadian Household Energy Costs. Darcy-Gail Ackerman. June 1979 (Price $3.00, 77 pages).

80-1 Government Incentives in Canada's Petroleum Industry. W. B. Friedenberg, Z. C. Slagorsky, and A. J. Walsh. March 1980 (Price $3.00, 43 pages).

80-2 A Regionalized Electricity Model: Preliminary Analyses. Kenneth D. Foat and Gerard J. Protti. April 1980 (Price $3.00, 61 pages).

80-3 Alternative Future Supplies of Oil in Canada and their Costs. Z. Charles Slagorsky. May 1980 (Price $3.00, 36 pages).

80-4 Prospects for Reduced Oil Consumption in Canada. W. B. Friedenberg and A. J. Nixon. May 1980 (Price $3.00, 34 pages).

81-1 Crude Oil Supply and Demand: Major Issues and Alternate Scenarios. Douglas J. Haughey. July 1981 (Price $7.00, 158 pages).

81-2 Natural Gas Pricing in Canada: An Economic Analysis. Andrea J. Nixon. October 1981 (Price $5.00, 116 pages).

82-1 Potential for Reducing Oil Demand through Conservation. Georgette Habib. September 1982 (Price $7.00, 47 pages).

83-1 Development Options for Maritime Coal. John A. Dawson. January 1983 (Price $7.50, 42 pages).

83-2 Development Options for Alberta and Saskatchewan Coal. Tricia Gibson. March 1983 (Price $7.50, 44 pages).

83-3 Development Options for British Columbia Coal. Kristi E. Varangu. April 1983 (Price $7.50, 107 pages).

83-4 The Impacts of Crude Oil Supply Changes and Supply Allocation. Douglas J. Haughey and Donald A. Bruton. May 1983 (Price $7.50, 72 pages).

83-5 An Analysis of Alternative Fiscal Systems for Oil Exploration and Production in Alberta. Walter Haessel, Gordon Morrison, and Alan Webster. July 1983 (Price $7.50, 104 pages).

Discussion Papers

82-1 Significance of Interregional Feedbacks for Canadian and Regional Energy Policy Decisions. Gordon W. Douglas and James A. MacMillan. March 1982 (Price $2.00, 10 pages).

83-1 The Alberta New Oil Royalty Formula: 74-04-01 to 82-12-31. Alan R. Webster. March 1983 (Price $6.00, 56 pages).

Proceedings

Markets for Canadian Uranium. Proceedings of a Seminar held on October 25, 1979, Calgary, Alberta (Price $10.00, 89 pages) ISBN 0-920522-08-4.

Economic Potential for Alternative Transportation Fuels: Methanol, Ethanol, Propane, Liquified Coal, Compressed Natural Gas and Hydrogen. Proceedings of a Seminar held on November 17, 1981, Calgary, Alberta. (Price $10.00, 83 pages) ISBN 0-920522-19-X.

World Oil Market Conference. Proceedings of a Conference held on October 18, 1982, Calgary, Alberta. Edited by Shane S. Streifel (Price $50.00, 220 pages) ISBN 0-920522-25-4.

Annual Report

Annual Report of the Board of Directors for the Period April 1, 1982 to March 31, 1983. ISBN 0-920522-30-0.

POOR

QUALITY

ORIGINAL